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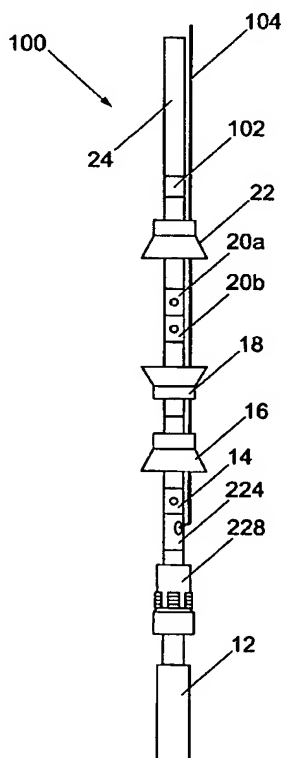
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(54) Title: WELL ABANDONMENT APPARATUS



(57) Abstract: A well abandonment apparatus (10) is described. The apparatus can be run on drillstring and does not require the use of explosives to sever the casing. The apparatus includes both a cutting device (12) to perforate and sever the casing and a sealing device (22) to prevent well fluids from reaching the surface whilst the well abandonment operation is proceeding.

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WELL ABANDONMENT APPARATUS

1

2

3 This invention relates to apparatus and a method for
4 treating wells, especially but not exclusively for
5 abandoning hydrocarbon-bearing wells.

6

7 When wells have reached the end of their useful
8 life, they need to be abandoned. The top of the
9 casing strings must be cut off near the wellhead,
10 whilst ensuring that no further hydrocarbons can
11 leak through the casing strings and into the
12 surrounding area. The bottom of the annulus between
13 the two innermost casings is in communication with
14 the formation. Therefore, if this annulus is not
15 completely sealed, hydrocarbons from the formation
16 could leak out. Usually, wells are abandoned using
17 explosives to sever the casings. These are harmful
18 for fish and the environment. Furthermore,
19 underwater explosions are difficult to control and
20 there is a risk of damaging the well plug, causing
21 it to leak.

22

1 According to the present invention there is provided
2 well treatment apparatus comprising a cutting tool;
3 a sealing device to seal a portion of a wellbore;
4 and an anchor means to anchor the apparatus with
5 respect to the wellbore.

6
7 Preferably, the sealing device comprises at least
8 one and preferably two annular cup devices typically
9 orientated in the same direction to provide a double
10 seal between the portion of the well beneath the
11 sealing device and the surface of the well.

12
13 Optionally, the sealing device comprises two annular
14 cup devices orientated in opposite directions (e.g.
15 with cups facing one another) to seal the portion of
16 the apparatus in between the two oppositely-
17 orientated devices from the rest of the bore.

18
19 Preferably, a first fluid circulation device is
20 positioned between the two oppositely orientated cup
21 devices.

22
23 Typically the cup devices can be cup-type seal
24 assemblies, typically with axially extending
25 conduits for e.g. control lines and fluid lines. A
26 preferred cup device can be constructed from a
27 packer (e.g. such as a gas line packer available
28 from Double-E, Inc), modified so that its rubber
29 part allows the packer to perform a sealing
30 function, and including bulkhead connections
31 providing axial passages through the packer.
32

1 Preferably, the apparatus adapted to attach to a
2 drillstring and the sealing device is typically
3 adapted to, in use, seal the annulus between the
4 drillstring and the innermost casing of the
5 wellbore.

6
7 Typically, the cup device has a cup-shaped body
8 (typically at least a portion of this is made from a
9 deformable material, such as high density rubber).
10 Preferably, a part of the cup device is adapted to
11 deform outwards to seal the annulus upon the
12 application of pressure from inside the cup-shaped
13 body. In use, fluid flowing into the cup-shaped
14 body typically deforms the cup-shaped body so that
15 the external face of the cup presses against the
16 inner face of the casing, preventing or restricting
17 fluid from flowing past the cup device.

18
19 Typically, a further fluid-circulating device is
20 located between the sealing device and the cutting
21 tool. Typically, fluid can be diverted between the
22 circulating devices by dropping a ball/dart into the
23 body of the apparatus.

24
25 Optionally, at least one further seal is located
26 beneath the cutting tool, to seal the portion of the
27 bore around the cutting tool from that below the
28 cutting tool. Preferably, the at least one further
29 seal is a cup-type seal assembly.

30
31 Preferably, the cutting tool comprises a jet cut
32 nozzle that is able to cut through casings that line

1 the bore. Preferably, the nozzle is movable e.g.
2 rotatable in two perpendicular planes (e.g.
3 horizontal and vertical) so that the nozzle can cut
4 circular apertures in the casing. Preferably the
5 nozzle/cutting tool is also rotatable through 360° to
6 enable the cutting tool to cut around the entire
7 circumference of the casing.

8
9 Optionally, the anchor means is located on the body
10 of the cutting tool. Alternatively, the anchor
11 means could be provided on a further sub separate
12 from the cutting tool.

13
14 Preferably, at least one part of the anchor means is
15 laterally extendable. The laterally extendable part
16 of the anchor means typically has a foot for
17 engaging a wall of a casing.

18
19 Preferably, the foot has a high-friction casing-
20 contacting surface. Typically, the casing-
21 contacting surface extends around the entire
22 circumference of the anchor means.

23
24 A typical anchor means can be provided by modifying
25 a packer device having an expandable anchor portion;
26 the modification typically includes the removal of
27 the interior packing material to leave a hollow bore
28 through the packer. Such packer devices typically
29 have an exterior anchor portion, which is expanded
30 on moving a first part of the anchor device relative
31 to a second part.

32

1 Optionally, the cutting tool has at least two (e.g.
2 three or more) circumferentially spaced feet, to
3 engage the interior of the casing at
4 circumferentially spaced locations. The or each
5 foot can be mounted on a moveable arm that can be
6 driven by a ram or alternatively at least one of the
7 feet can be static e.g. provided on the body of the
8 cutting tool, or on an extension of the body.

9
10 According to a second aspect of the invention, there
11 is provided a method of treating a well, including
12 the steps of:

13
14 inserting well treatment apparatus into a cased
15 wellbore, the apparatus including a cutting
16 tool, a sealing device and an anchor means;

17
18 perforating the innermost casing in two
19 vertically spaced positions; and

20
21 injecting cement into a portion of the annulus
22 between the two innermost casing strings to
23 seal the annulus;

24
25 whereby the method includes the step of using
26 the anchor means to anchor the apparatus to the
27 cased wellbore.

28
29 Typically, the method includes the step of pressure
30 testing the innermost casing before the first
31 perforation is made by injecting a fluid into the
32 wellbore below the sealing means.

1 Typically, the method includes the step of pressure
2 testing the annulus before the second perforation is
3 made by injecting a fluid into the wellbore below
4 the sealing means and measuring the equilibrium rate
5 of pumping as the fluid flows through the first
6 perforation into the annulus.

7

8 Optionally, the method includes the step of pressure
9 testing the annulus after the second perforation has
10 been made by injecting a fluid into the annulus to
11 check that there are no blockages in the part of
12 that annulus lying between the vertically spaced
13 perforations.

14

15 Typically, the sealing device includes two
16 oppositely orientated cup devices, and the cement is
17 injected into the annulus from an aperture in the
18 apparatus located between these two cup devices.

19

20 Optionally, the method includes the step of pressure
21 testing the sealed annulus by positioning the
22 apparatus so that the sealing device lies between
23 the two vertically spaced perforations and by
24 injecting fluid into the wellbore below the sealing
25 device.

26

27 Preferably, the method includes the step of using
28 the cutting tool to sever the casings above the
29 perforations after the annulus has been sealed, and
30 typically tested for seal integrity.

31

1 Typically, the method including the step of
2 undertaking at least one pressure test by injecting
3 fluids, whereby during the pressure test, the
4 apparatus is anchored to the casing by the anchor
5 means to counter the upwards force on the apparatus
6 by the injected fluids.

7

8 Typically, the well treatment apparatus is mounted
9 on a drillstring and is manoeuvred in the wellbore
10 by raising and lowering the drillstring.

11

12 Typically the fluid used in the pressure tests is
13 water, but in some circumstances cement or other
14 fluids can be used.

15

16 An embodiment of the invention will now be described
17 by way of example only and with reference to the
18 following drawings, in which:-

19

20 Fig 1 shows a partial cross-section of an
21 abandonment string inserted into a wellbore to
22 be abandoned;

23 Fig 2 shows a partial cross-section of the
24 abandonment string piercing the 9 5/8" casing;
25 Fig 3 shows a partial cross-section of the
26 abandonment string making a second, higher cut
27 in the 9 5/8" casing;

28 Fig 4 shows a partial cross-section of the
29 abandonment string injecting cement into the
30 annulus between the cuts;

1 Fig 5 shows a partial cross-section of the
2 abandonment string performing a final pressure
3 test on the cemented annulus;
4 Fig 6 shows a partial cross-section of the
5 abandonment string cutting through all the
6 casing strings at the wellhead;
7 Fig 7 shows a schematic cross-section of the
8 abandonment string pressure testing the 9 5/8"
9 casing string;
10 Fig 8 shows a schematic cross-section of the
11 abandonment string making a cut in the 9 5/8"
12 casing and pressure testing the annulus between
13 the 9 5/8" casing and the 13 3/8" casing;
14 Fig 9 shows a schematic cross-section of the
15 abandonment string making a second cut in the 9
16 5/8" casing;
17 Fig 10 shows a schematic cross-section of an
18 integrity check of the cement in the annulus
19 between the two cuts;
20 Fig 11 shows a schematic cross-section of
21 cement being injected into the annulus between
22 the two cuts;
23 Fig 12 shows a schematic cross-section of the
24 cement in the annulus between the cuts being
25 pressure tested;
26 Fig 13 shows a schematic cross-section of the
27 casings being cut near the wellhead;
28 Fig 14 shows a cross section of three cup-type
29 seal assemblies mounted on two circulating
30 subs;
31 Fig 15 shows a side view of a cutting tool;

1 Fig 16 shows a side view of a portion of a
2 cutting tool;
3 Fig 17 shows a schematic diagram of an
4 abandonment string;
5 Fig 18 shows a perspective view of the
6 abandonment string of Fig 17;
7 Fig 19 shows a perspective view of a cup-type
8 assembly;
9 Fig 20 shows an end view of a body member of
10 the cup-type assembly of Fig 19;
11 Fig 21 shows a cross-section along the line A-A
12 of Fig 20;
13 Fig 22 shows an enlarged view of circle B of
14 Fig 21;
15 Fig 23 shows an end view of a cup-type seal of
16 Fig 19;
17 Fig 24 shows a cross-section along the line A-A
18 of Fig 23;
19 Fig 25 shows an end view of a shaft of the cup-
20 type seal assembly of Fig 19;
21 Fig 26 shows a cross-section along the line A-A
22 of Fig 25;
23 Fig 27 shows an enlarged view of region B of
24 Fig 26;
25 Fig 28 shows a side view with interior detail
26 of a flange of the shaft of Fig 25 and
27 Fig 29 shows a side view of the anchor of Figs
28 17 and 18.
29
30 As shown in Fig 1, an abandonment string 10
31 typically comprises a cutting tool 12, a first
32 circulating sub 14, two oppositely orientated cup-

1 type seal assemblies 16 18, a second circulating sub
2 20, a third cup-type seal assembly 22 and drill pipe
3 24.

4

5 An enlarged view of cup-type seal assemblies 16, 18,
6 22 and circulating subs 14, 20 is shown in Fig 14.

7 Cup-type seal assemblies 16 and 22 provide two
8 permanent barriers between the hydrocarbon bearing
9 formation and the surface.

10

11 Optionally, a second cup-type seal assembly and sub
12 arrangement may be provided beneath the cutting tool
13 12. This could be useful if the plug 44 in the
14 innermost casing has not formed a perfect seal. As
15 shown in Fig 1, the arrangement could comprise a sub
16 26, fourth and fifth cup-type seal assemblies 28, 30
17 arranged back-to-back, a further sub 32 and a sixth
18 cup-type seal assembly 34. This cup-type seal
19 assembly and sub arrangement is inverted as compared
20 with the arrangement above the cutting tool 12,
21 except that the subs 26 and 32 can be ordinary subs
22 instead of circulating subs. It is not necessary to
23 have this entire arrangement; cup-type seal assembly
24 28 would be sufficient, or cup-type seal assemblies
25 28 and 34, if a double seal is required.

26

27 The cutting tool 12 is best shown in Figs 15 and 16.
28 It has a rotatable jet cut nozzle 70, which can cut
29 through casing 36. Cutting nozzle 70 is rotatable
30 in both horizontal and vertical planes to allow the
31 cutting of communication ports (i.e. cutting nozzle
32 can cut in two dimensions). Cutting tool 12 has a

1 pair of anchoring devices 74 that are axially spaced
2 along the body of the tool, to anchor the tool 12 in
3 the casing 36. Each anchoring device 74 has three
4 feet 78 that are circumferentially spaced around the
5 body of the tool 12 and each foot is attached to the
6 body of the tool 12 by a pair of link arms 72 that
7 are each pivotally coupled at one end to an eye on
8 the foot and at the other end to a respective eye on
9 the body. One of the eyes on the body is mounted on
10 a central plate that is driven axially by a
11 hydraulic ram to push the eyes on the body together
12 thereby extending the feet by means of the pivotal
13 connections so that the feet move laterally to
14 contact the casing 36. Fig 16 shows one embodiment
15 of a part of cutting tool 12, which has a foot 78,
16 mounted on a pair of link arms 72. The foot 78
17 typically has an abrasive outer surface with e.g.
18 serrations so that there is high friction between
19 the foot 78 and casing 36 when the two are in
20 contact. Fig 16 also depicts an optional second
21 foot 80, which is mounted on an extension 82 of the
22 body of the cutting tool 12. The cutting tool
23 should have at least one extendable foot 78, and
24 optionally at least one other foot 78 or 80, or
25 other high friction casing contacting surface.
26 Typically there are two or three feet 78 each
27 circumferentially mounted on pairs of linking arms
28 72 which are circumferentially spaced around the
29 tool 12. As shown in Fig 15, more than one plate 74
30 may be provided.

31

1 The drill pipe 24 extends to the surface.
2 Umbilicals also extend from the surface to the
3 cutting tool 10.
4

5 The abandonment string 10 is shown inside a
6 wellbore, which has several layers of casing: 9
7 5/8", 13 3/8", 20" and 30", which are respectively
8 designated by numbers 36, 38, 40 and 42.
9

10 Figs 17 and 18 show a second embodiment of
11 abandonment string 100 and like parts are designated
12 by like numbers. Abandonment string 100 differs
13 from abandonment string 10 in that cup-type seal
14 assemblies 16 and 18 are shown separated by subs,
15 whereas in Fig 10, these are shown back to back.
16

17 Like the Fig 1 embodiment, abandonment string 100 is
18 run on drillpipe 24. Starting from the top of the
19 string, the first component is an optional safety
20 joint 102. This provides a means of disconnecting
21 drillpipe 24 from abandonment string 100 should the
22 need arise.
23

24 A flex pipe 104 runs along the side of drillstring
25 24 and the rest of abandonment string 100. Flex
26 pipe 104 typically comprises a 3/4 inch 15K fluid
27 power hose to supply fluid (slurry) to cutting tool
28 12. Also running along the side of drillstring 24
29 parallel to flex pipe 104 are electrical and
30 hydraulic umbilical lines (not shown) to power and
31 control the cutting tool 12.
32

1 The next component in the string is cup-type seal
2 assembly 22 and associated flex pipe assembly 200.
3 Cup-type seal assembly 22 is shown in more detail in
4 Figs 19 to 28. Cup-type seal assemblies 16, 18
5 further down the string are typically exactly the
6 same, but for ease of reference numbering, the cup-
7 type seal assembly is denoted simply as 22.

8
9 Cup-type seal assembly 22 includes a body member
10 106, a seal 108, a shaft assembly 110 and an o-ring
11 seal 112. Body member 106 is substantially
12 cylindrical. It has a shaft-engaging portion 120
13 and a seal-engaging portion 122. Shaft-engaging
14 portion 120 has a smooth outer surface of constant
15 diameter. Shaft-engaging portion 120 is divided
16 into two portions with different inner diameters; an
17 end portion 150 of diameter 188mm and a mid portion
18 152 of diameter 175mm; end portion 150 and mid
19 portion 152 are divided by a step 125, which lies at
20 53mm from the end of body member 106. It should be
21 noted that throughout this specification all
22 dimensions are exemplary rather than limiting

23
24 The outer end of the end portion 150 is provided
25 with four holes 123 equally spaced around the
26 circumference for the insertion of grub screws.
27 Adjacent to holes 123, end portion 150 has 7.375-6
28 ACME-2G threads 127 which terminate a short distance
29 before step 125.

30
31 Mid portion 152 is provided with a groove 124 to
32 accommodate o-ring seal 112. Mid portion 152 then

1 continues uniformly up to a distance of 92mm from
2 the end of the shaft-engaging portion 120, where
3 there is a further step 128 which marks the boundary
4 between the shaft-engaging portion 120 and the seal-
5 engaging portion 122.

6
7 The seal-engaging portion 122 comprises an extension
8 of the shaft-engaging portion and is provided with
9 undulations on both of its inner and outer surfaces.
10 The seal-engaging portion 122 is thinner than the
11 shaft-engaging portion 120, having a larger inner
12 diameter and the same outer diameter. Eight radial
13 apertures 126 are provided in the seal-engaging
14 portion 122, equally spaced around the
15 circumference; more or fewer apertures could be
16 provided here, or even none at all.

17
18 Seal 108 is best shown in Figs 24 and 25. Seal 108
19 is also basically cylindrical with a body-engaging
20 portion 132 and a radially-extending end 130. Body-
21 engaging portion 132 is shaped to co-operate with
22 the seal-engaging portion 122 of body member 106.
23 Body-engaging end 132 of seal 108 is provided with a
24 cylindrical recess 134 corresponding to the seal-
25 engaging end 122 of body member 106, i.e. the
26 cylindrical recess 134 has undulating inner and
27 outer surfaces adapted to co-operate with the
28 undulations on seal-engaging end 122. Seal 108 is
29 coupled to body member 106 by the seal-engaging end
30 122 of body member 106 engaging the co-operating
31 cylindrical recess 134 of seal 108, with end 133 of

1 seal 108 abutting against step 128 of body member
2 106; the undulations act to resist separation.

3
4 Radially-extending end 130 is an extension of a
5 body-engaging end 132 and it tapers outwards from
6 body-engaging end 132, with both the inner and outer
7 diameters increasing. The inner diameter increases
8 at a greater rate than the outer diameter, so that
9 the radially-extending end 130 gets thinner as it
10 tapers outwards.

11
12 Seal 108 is preferable made of a rubber composition,
13 preferably 70-80 durometer Nitrile which is suitable
14 for hydrocarbon use; however other materials could
15 also be used.

16
17 Shaft assembly 110, as best shown in Figs 25 to 28
18 includes a hollow shaft 140 and flange 142 extending
19 outwardly of shaft 140. The shaft 140 has a box and
20 a pin connection on respective opposite ends.

21 Flange 142 is shaped to engage and co-operate with
22 the shaft-engaging end 120 of body member 106.

23 Flange 142 is provided with 7.375.6 ACME-2G screw
24 threads 143 on its outer surface for connection with
25 screw threads 127 on body member 106. Flange 142
26 has a radial projection 144 on the end of flange 142
27 closest to the pin connection, and a stepped recess
28 147 on the opposite end of flange 142. Between
29 radial projection 144 and threads 143 is an
30 unthreaded gap 145.

31

1 Flange 142 is provided with eight passages 146 of
2 11.8mm diameter extending through flange 142
3 parallel to the axis of shaft assembly 110.
4 Passages 146 are threaded at their upper and lower
5 ends for the first 20mm for engagement with
6 respective bulkhead connections (not shown). One
7 bulkhead connection is supplied for each end of each
8 passage 146. Passages 146 are to enable the
9 electrical and hydraulic umbilical lines to continue
10 past cup-type seal assembly 22; each umbilical line
11 terminates at the first bulkhead connection, the
12 first bulkhead connection provides a continuation of
13 the umbilical line through respective passage 146 to
14 the second bulkhead connection on the opposite side
15 of flange 142, which is in turn connected to a
16 further umbilical line on the other side of flange
17 142. The bulkhead connectors can each be sealed
18 closed, so that if any passage 146 is not being
19 used, the respective bulkhead connectors are sealed
20 so that no fluids can get through that passage 146.
21
22 Two further passages 141, 148 of larger (25.4mm)
23 diameter are provided in flange 142. Passages 141,
24 148 are threaded for the first 5/8 inches at their
25 upper and lower ends.
26
27 Passage 141 allows the flex pipe 104 to continue
28 through flange 142. Passage 141 also has a bulkhead
29 connection, in the form of flex pipe assembly 200.
30 Flex pipe assembly 200 is a means of connecting a
31 portion of flex pipe 104 on one side of cup-type
32 seal assembly 22 to a further portion of flex pipe

1 104 on the other side. Flex pipe assembly 200
2 typically includes a further portion of flex pipe
3 104 which passes through passage 141 in flange 142;
4 flex pipe assembly 200 typically includes one or
5 more seals (not shown) to seal between the exterior
6 of flex pipe 104 and the interior of passage 141.

7
8 Two blind passages 149 are also provided in the
9 flange, equally spaced on either side of passage
10 141. Blind passages 149 are typically used to
11 receive bolts to secure flex pipe assembly 200 to
12 shaft assembly 110.

13
14 Remaining passage 141 also has a bulkhead connection
15 on each side of flange 142. Passage 141 can be used
16 to accommodate a return fluid line or an extra flex
17 pipe for slurry (not shown) or alternatively, if not
18 used, it could be sealed closed at its bulkhead
19 connections.

20
21 Passages 141, 146, 148, 149 are circumferentially
22 distributed on flange 142.

23
24 Referring back to Fig 18, cup-type seal assembly 22
25 is orientated in the string 100 with the seal end
26 (and the box connection of shaft assembly 110)
27 pointing downwards. The pin of shaft assembly 110
28 is attached to drillstring 24 as shown in Fig 17.

29
30 When fluid flows into the seal end of cup-type seal
31 assembly 22 (i.e. fluid flowing upwards on the
32 outside of string 100 in this embodiment) the

1 radially-extending end 130 of seal 108 is pushed
2 outwards to engage the casing wall. The greater the
3 pressure from the fluid, the more the radially-
4 extending end 130 is pushed against the casing, and
5 the better the seal. Therefore, fluid flowing
6 upwards in the annulus between the string 100 and
7 the innermost casing string cannot get past seal 22.

8
9 The box of shaft assembly 110 is attached to a pin-
10 pin sub 202, followed by a crossover sub 204, two
11 pin-box ported subs 20a, 20b, a further cross-over
12 sub 210 and a pin-box sub 212. (Note that in this
13 embodiment, there are two pin-box ported subs 20,
14 whereas in the Fig 1 embodiment only one was shown).

15
16 At this point in the string is cup-type seal
17 assembly 18; this is exactly the same as cup-type
18 seal assembly 22 and the above description of cup-
19 type seal assembly 22 is equally applicable here.
20 However, the orientation of cup-type seal assembly
21 18 is the reverse of the former seal assembly 22;
22 i.e. where cup-type seal assembly 22 has its seal
23 108 pointing downwards, cup-type seal assembly 18
24 has its seal pointing upwards. Thus, in this case,
25 it is the box connection of shaft assembly 110 that
26 is attached to pin-box sub 212. Because of the
27 opposite orientation, fluid flowing downwards in the
28 annulus between string 100 and the innermost casing,
29 is stopped by cup-type seal assembly 18.

30
31 Also as described above, a further flex pipe
32 assembly 200 allows flex pipe 104 to pass through

1 passage 141 in flange 142 whilst forming a seal
2 around the outside of the passage.

3
4 The pin connection of shaft assembly 110 is attached
5 to pin-box sub 214 and the drillstring continues
6 with box-box sub 216 and further pin-box sub 218.

7
8 A further cup-type seal assembly 16 and respective
9 flex pipe assembly 200 is attached to pin-box sub
10 218. Cup-type seal assembly 16 is exactly the same
11 as cup-type seal assemblies 18, 22 described above,
12 and has the same orientation in the string as cup-
13 type seal assembly 22 (i.e. opposite to assembly
14 18). Thus, cup-type seal assemblies 16, 22 both act
15 to prevent fluid flowing upwards from the well to
16 the surface.

17
18 Connected to shaft assembly 110 of cup-type seal
19 assembly 16 is a pin-pin sub 220 and pin-box ported
20 sub 14. Pin-box ported sub 14 has a blind ending,
21 and three transverse passages (although only one is
22 necessary) leading from an inner bore to the outside
23 of abandonment string 100, providing fluid
24 communication with the outside of the string 100.
25 Ported sub 14 allows for pressure testing beneath
26 cup-type seal assembly 16, circulating through
27 perforations as required and pressure monitoring
28 during perforations. It also allows a fluid return
29 path (via the drillpipe 24) for the cutting tool
30 power fluid whilst cutting operations are in
31 progress. Furthermore, bullheading the perforated
32 casing annuli can be carried out via sub 14. Shield

1 bracket 226 is provided on sub 14. The next element
2 is apertured sub 224, which has at least one side
3 aperture to allow the entry of flex pipe 104 into a
4 hollow bore of apertured sub 224. Apertured sub 224
5 may also have a further aperture for entry of a
6 further fluid return pipe (not shown) into the
7 hollow bore.

8
9 Attached to apertured sub 224 is anchor sub 228;
10 this is best shown in Fig 29. Anchor sub 228
11 replaces the anchoring device 74 shown in Figs 15
12 and 16 (used in abandonment string 10). Anchor sub
13 228 is a modification of a casing packer.

14
15 The modification typically includes the removal of
16 the inner packing material, leaving a central hollow
17 bore for the passage of flex pipe 104 and the
18 umbilicals. Anchor sub 228 has a first portion 232
19 and second portion 234 which are slideable relative
20 to each other; the second portion 234 having a
21 tapered portion 238, which in turn has a reduced-
22 diameter extension 236. The first portion 232 has
23 grippers 240 on the end closest to the second
24 portion. To activate anchor 228, the second portion
25 234 is moved upwards relative to first portion 232,
26 which causes grippers 240 to be pushed radially
27 outwards as they travel along tapered portion 238.
28 Grippers 240 engage the inner surface of the cased
29 wellbore to anchor abandonment string 100 to the
30 casing.

31

1 Attached to anchor sub 228 is cutting tool 12, which
2 can be the same anchoring tool as shown in Fig 15.
3 Cutting tool 12 in this embodiment does not need to
4 have feet 78 as abandonment string 100 already has
5 an anchor 228, although these may be still be
6 provided if desired.

7
8 Cutting tool 12 has a hollow internal passage to
9 allow passage of flex pipe 104 and the umbilical
10 lines (not shown). Cutting tool 12 has a cutting
11 nozzle 70 (see Fig 15). The cutting tool 230 is
12 controlled and powered by the umbilicals; fluid
13 (typically slurry) is supplied to cutting nozzle 70
14 by flex hose 104. The remaining features of cutting
15 tool 12 have already been described above with
16 reference to Fig 15 and the abandonment string 10
17 embodiment.

18
19 In use, when the corrosion cap/temporary abandonment
20 cap has been removed from the well, a drill string
21 with a rock bit is run into the wellbore, to check
22 that it is free of obstructions. The drill string
23 is typically made up of 3½" or 5" drill pipe.

24
25 The abandonment string 10, 100 is made up and run
26 into the hole to a depth of typically 100-400 metres
27 (in some cases up to several thousand metres)
28 beneath the wellhead. The top drive is then made up
29 or the string is connected to a circulation device.

30
31 With abandonment string 10, the cutting tool 12 in
32 the string is then anchored to e.g. the 9 5/8"

1 optionally below the wellhead by extending the rams
2 72 so that the feet 78 contact the casing 36. The
3 abandonment string 10 is thus held fixed relative to
4 the casing 36 by friction between the feet 78 and
5 the casing 36. If abandonment string 100 is used,
6 anchor 228 is engaged as described above by moving
7 second portion 234 towards first portion 232 until
8 the grippers 240 grip the casing sufficiently.

9
10 As shown in Fig 7, the casing 36 is pressure tested,
11 to check its integrity. This is done by pumping
12 fluid down through the abandonment string 10, 100
13 and out through an aperture in circulating sub 14.
14 The fluid is constrained within the area bounded by
15 an existing plug 44 (fitted when the wellbore was
16 temporarily abandoned), the cup-type seal assemblies
17 16, 22 and the casing 36. This tests the pressure
18 integrity of the casing and of the plug 44 and
19 identifies whether there are any fissures through
20 which significant amounts of hydrocarbons can leak
21 from the formation.

22
23 It may be advantageous to only engage the anchor
24 after the pressure has already begun to build up.
25 The anchor is useful to prevent the pressure build
26 up underneath cup-type seal assembly 16 from forcing
27 abandonment string 100 out of the well.

28
29 Assuming that the casing 36 and the plug 44 do not
30 have any substantial leaks, the cutting tool 12 then
31 cuts two (typically circular) holes 46, 48 in
32 opposite sides of the casing 36, as shown in Figs 2

1 and 8. It is not necessary to cut two holes; one
2 would suffice, nor is it necessary for the holes to
3 be opposite each other.

4
5 A second pressure test is then performed by pumping
6 fluid 50 (e.g. water) through the abandonment string
7 and out through the aperture in circulating sub 14,
8 in the same manner as the first pressure test. The
9 fluid 50 passes out through the holes 46 and 48 and
10 into the annulus 52 between the casing 36 and the
11 casing 38. Some of the fluid 50 may escape down the
12 annulus 52 and into the formation. The rate of
13 pumping is varied so that equilibrium is reached
14 between the amount of fluid 50 entering and leaving
15 the annulus 52. The equilibrium rate of pumping and
16 pressure are recorded. A typical equilibrium rate
17 might be 2-3 barrels per minute at a pressure of
18 3,000 pounds per square inch. This test is done to
19 establish a bench mark for the next pressure test.
20 It also establishes the integrity of the casing 38;
21 if there is very low pressure in the annulus 52
22 after pumping fluid 50 into it, that could indicate
23 leaks in the casing 38 or the cement job. If there
24 is a very high back pressure, which could be caused
25 by hydrocarbons in the annulus/formation, the excess
26 fluid will have to be removed via the string before
27 proceeding.

28
29 The anchoring means are then deactivated to release
30 the cutting tool 12 from the casing 36 and the
31 abandonment string 10, 100 is then raised so that
32 the cutting tool 12 is approximately 400-500 feet

1 above the first cuts 46,48 as shown for example in
2 Figs 3 and 9. The anchoring means are then
3 reactivated so that the cutting tool 12 is re-
4 anchored to the casing 36 (i.e. by extending the
5 link arm 72 to push the feet 78, 80 against the
6 casing 36 in the Fig 1 embodiment, or by moving the
7 first and second portions 232, 234 away from each
8 other in the Fig 17 embodiment). A pair of second
9 cuts 54, 56 are made with the cutting tool 12 in
10 opposite sides of the casing 36 as before. Again,
11 it is not necessary to cut twice; one cut would
12 suffice. In some cases a further pressure test as
13 described previously can be carried out through the
14 newly made cuts 54, 56, but this is not necessary.

15
16 The anchoring device is then deactivated to release
17 the cutting tool 12 from the casing and the
18 abandonment string 10 is lowered down the borehole
19 so that the cup-type seal assemblies 16 and 22 are
20 between the two sets of cuts 46, 48 and 54, 56, as
21 shown in Fig 10. Fluid is then pumped from the
22 lower sub through cuts 46, 48 and into the annulus
23 52 between the two sets of cuts 46, 48 and 54, 56.
24 If the fluid pathway is open in the annulus 52,
25 fluid pumped through the string 10 should flow
26 through cuts 54, 56 without significant measurable
27 pressure build up at surface.

28
29 The abandonment string 10 is then detached from the
30 casing, lowered and re-anchored so that the first
31 cuts 46, 48 are positioned between cup-type seal
32 assemblies 18 and 22, as shown in Fig 11. A ball or

1 dart is dropped through the abandonment string 10 so
2 that it diverts fluid from the circulating sub 14.
3 Cement is then pumped down the abandonment string
4 10. The cement 58 passes out of the hole 20 in
5 circulating sub and into the annulus 52.

6
7 When no more cement can be pumped in at a reasonable
8 rate and pressure (with reference to the readings
9 taken earlier) this indicates that the annulus
10 between the cuts is well sealed. Alternatively a
11 cement slug of a known volume can be injected into
12 the string and is pumped through the tool 12. The
13 volume of the slug is calculated to create a plug
14 extending the length of the annulus between the cuts
15 46, 48 and the cuts 56, 58. Typically the distance
16 between the first and second cuts is at least 100
17 feet, and typically an excess of cement (e.g. 2-
18 300%) is used in order to ensure that the annular
19 cement plug is sufficiently long.

20

21 The anchoring devices are then deactivated and the
22 string 10 is pulled up out of the borehole before
23 the cement sets. Excess cement that has emerged
24 from the upper cuts 56, 58 is wiped out of the bore
25 by the seals on the tool 12. At this time, the tool
26 can be redressed to remove the ball/dart from the
27 circulating sub 14 so that fluid can circulate
28 through the sub 14 once more.

29

30 When the new cement is set, the string 10 is run
31 into the borehole again so that the cup-type seal
32 assemblies 16, 22 are in between cuts 46, 48 and

1 cuts 54, 56, as shown in Figs 5 and 12. The annular
2 plug of cement in the section 60 of annulus 52
3 between the cuts 46, 48 and cuts 54, 56 should now
4 be solid. To test this, fluid (e.g. water) is then
5 pumped down the string 12 and through the hole in
6 the circulating sub 14. If no significant injection
7 of fluid into the annulus 52 is possible, then this
8 proves that the cement job has been successful and
9 that the section 60 of annulus 52 is firmly sealed.

10

11 If this is the case, the tool 10 is unanchored,
12 raised and re-anchored so that the cutter of the
13 cutting tool 12 is near the wellhead. The cutting
14 tool 12 is then used to cut through all the casings
15 36, 38, 40, 42 by continuous cutting while the head
16 rotates around 360°.

17

18 In the case of the string 100, the procedure is the
19 same but the port 20a between the cups 22,18 can
20 optionally be used for cement injection, whereas the
21 other port 20b can be used for pressure testing
22 between the upper 22 and lower 18 seals prior to any
23 perforations being made. Thus testing of the upper
24 and the lower seals 22, 16 can optionally be done
25 without moving the string.

26

27 Modifications and improvements may be incorporated
28 without departing from the scope of the invention.
29 For example, after the cement has been injected into
30 the annulus, instead of withdrawing the string
31 10,100 back to surface, the string 10,100 can be
32 pulled up just above the upper perforations 54,56,

1 to wait on cement (if a cement slug has been used)
2 or can be pulled up until the ports 20 are above the
3 wellhead, where the cement can be purged from the
4 drillstring, the port 20a, and the area between the
5 seals 22,18. When the cement has been purged (if
6 necessary) then the string 10,100 can be run back
7 into the hole to test the integrity of the annular
8 cement seal at 60, by pumping seawater through
9 either of ports 20a and 20b. This therefore allows
10 the whole operation to be completed in a single run.
11 In a further modification of the method, further
12 radially outward annuli can be sealed in exactly the
13 same way, optionally on the same run in the hole, by
14 cutting through the two innermost layers of casing
15 and into the second annulus behind that already
16 sealed. Typically the plug in the second annulus
17 overlaps the first plug, in accordance with normal
18 procedures, and this can be achieved by making the
19 first cut for the second plug between the first and
20 second cuts of the first, and then raising the
21 string 10,100 to a level above the second (upper)
22 cuts of the first plug, before making the second
23 (upper) cuts for the second plug. Clearly the outer
24 plug could be set at a lower level than the first
25 plug.

26
27 The high pressure rating of the tool allows control
28 of hydrocarbons behind the perforated casings, and
29 also can be used to inject behind numerous radially
30 outward casings outside the innermost casing, or to
31 break down the formation at these points. This
32 high-pressure capability is useful if bullheading is

1 required. Cutting through radially outward casing
2 strings can be detected by observing pressure drops
3 in the slurry hose.

4

5 When moving the string 10,100 through the hole the
6 plunger effect can be minimised by allowing free
7 passage of fluid through the string 10,100. Also,
8 swabbing can be minimised when pulling out by
9 pumping fluid down the string 10,100.

10

11 Embodiments of the present invention have the
12 advantage that no explosives are used, which makes
13 it more environmentally friendly. This also
14 eliminates the risk of shattering the well plugs
15 using explosives. Also, by following the method
16 described above, the casing can be perforated and
17 pressure tested, cement injected into the annulus
18 between casings to seal the annulus and the casings
19 severed all on a single run operation. Furthermore,
20 the cutting tool can also be used to cut the
21 concrete pancake at the top of the wellhead,
22 breaking it up and hence reducing the amount of
23 weight to be lifted after the casings are severed.
24 The equipment is usually run on a drillstring, and
25 can be run on coil tubing, so the abandonment string
26 can be run from a derrick vessel, or a floating/
27 jack-up rig, without requiring more expensive and
28 permanent platforms, or even diving support vessels.
29

1 Claims

2

3 1. Well treatment apparatus comprising a cutting
4 tool; a sealing device to seal a portion of a
5 wellbore; and an anchor means to anchor the
6 apparatus with respect to the wellbore.

7

8 2. Well treatment apparatus as claimed in claim
9 1, wherein the sealing device comprises at least one
10 annular cup-type device.

11

12 3. Well treatment apparatus as claimed in claim 1
13 or claim 2, adapted to attach to a drillstring.

14

15 4. Well treatment apparatus as claimed in claim
16 3, wherein the sealing device is adapted to, in use,
17 seal the annulus between the drillstring and the
18 innermost casing of the wellbore.

19

20 5. Well treatment apparatus as claimed in claim
21 4, wherein the cup device has a cup-shaped body and
22 a part of the cup device is adapted to deform
23 outwards to seal the annulus upon the application of
24 pressure from inside the cup-shaped body.

25

26 6. Well treatment apparatus as claimed in any
27 preceding claim, wherein the sealing device
28 comprises more than one annular cup device, at least
29 two of the annular cup devices being orientated in
30 the same direction to provide a double seal between
31 the portion of the wellbore beneath the sealing
32 device and the surface of the wellbore.

1 7. Well treatment apparatus as claimed in any
2 preceding claim, wherein the sealing device
3 comprises more than one annular cup device and at
4 least two of the annular cup devices are orientated
5 in opposite directions to seal the portion of the
6 apparatus in between the two oppositely-orientated
7 devices from the rest of the bore.

8
9 8. Well treatment apparatus as claimed in claim
10 7, wherein at least one fluid-circulation device is
11 located between the two oppositely-orientated cup
12 devices.

13
14 9. Well treatment apparatus as claimed in any
15 preceding claim, wherein a fluid-circulation device
16 is located below the sealing device.

17
18 10. Well treatment apparatus as claimed in any
19 preceding claim, including at least one further
20 sealing device at the downhole end of the apparatus,
21 the further sealing device being adapted to seal the
22 portion of the borehole in which the rest of the
23 apparatus is located from the portion of the
24 borehole below the apparatus.

25
26 11. Well treatment apparatus as claimed in any
27 preceding claim, wherein the cutting tool comprises
28 a jet cut nozzle capable of cutting through wellbore
29 casing, capable of rotation through 360°, and
30 capable of rotation in at two perpendicular planes.

31
32 12. Well treatment apparatus as claimed in any

1 preceding claim, wherein at least one part of the
2 anchor means is laterally extendable.

3

4 13. Well treatment apparatus as claimed in claim
5 12, wherein the laterally extendable part of the
6 anchor means has a high-friction surface for
7 engaging the casing.

8

9 14. Well treatment apparatus as claimed in claim
10 12 or claim 13, wherein the anchor means has a
11 radial casing-contacting surface.

12

13 15. A method of treating a well, including the
14 steps of:

15

16 inserting well treatment apparatus into a cased
17 wellbore, the apparatus including a cutting
18 tool, a sealing device and an anchor means;

19

20 perforating the innermost casing in two
21 vertically spaced positions; and

22

23 injecting cement into a portion of the annulus
24 between the two innermost casing strings to
25 seal the annulus;

26

27 whereby the method includes the step of using
28 the anchor means to anchor the apparatus to the
29 cased wellbore.

30

31 16. A method as claimed in claim 15, including the

1 step of pressure-testing the innermost casing before
2 the first perforation is made by injecting a fluid
3 into the wellbore below the sealing means.
4

5 17. A method as claimed in claim 15 or claim 16,
6 including the step of pressure testing the annulus
7 before the second perforation is made by injecting a
8 fluid into the wellbore below the sealing means and
9 measuring the equilibrium rate of pumping as the
10 fluid flows through the first perforation into the
11 annulus.
12

13 18. A method as claimed in any of claims 15 to 17,
14 including the step of pressure testing the annulus
15 after the second perforation has been made by
16 injecting a fluid into the annulus to check that
17 there are no blockages in the part of that annulus
18 lying between the vertically spaced perforations.
19

20 19. A method as claimed in any of claims 15 to 18,
21 wherein the sealing device includes two oppositely-
22 orientated cup devices, and the cement is injected
23 into the annulus from an aperture in the apparatus
24 located between these two cup devices.
25

26 20. A method as claimed as claimed in any of
27 claims 15 to 19, including the step of pressure
28 testing the sealed annulus by positioning the
29 apparatus so that the sealing device lies between
30 the two vertically spaced perforations and by
31 injecting fluid into the wellbore below the sealing
32 device.

1 21. A method as claimed in any of claims 15 to 20,
2 including the step of using the cutting tool to
3 sever the casings above the perforations after the
4 annulus has been sealed.

5
6 22. A method as claimed in any of claims 15 to 21,
7 the method including the step of undertaking at
8 least one pressure test by injecting fluids, whereby
9 during the pressure test, the apparatus is anchored
10 to the casing by the anchor means to counter the
11 upwards force on the apparatus by the injected
12 fluids.

13
14 23. A method as claimed in any of claims 15 to 22,
15 wherein the well treatment apparatus is mounted on a
16 drillstring and is manoeuvred in the wellbore by
17 raising and lowering the drillstring.

18

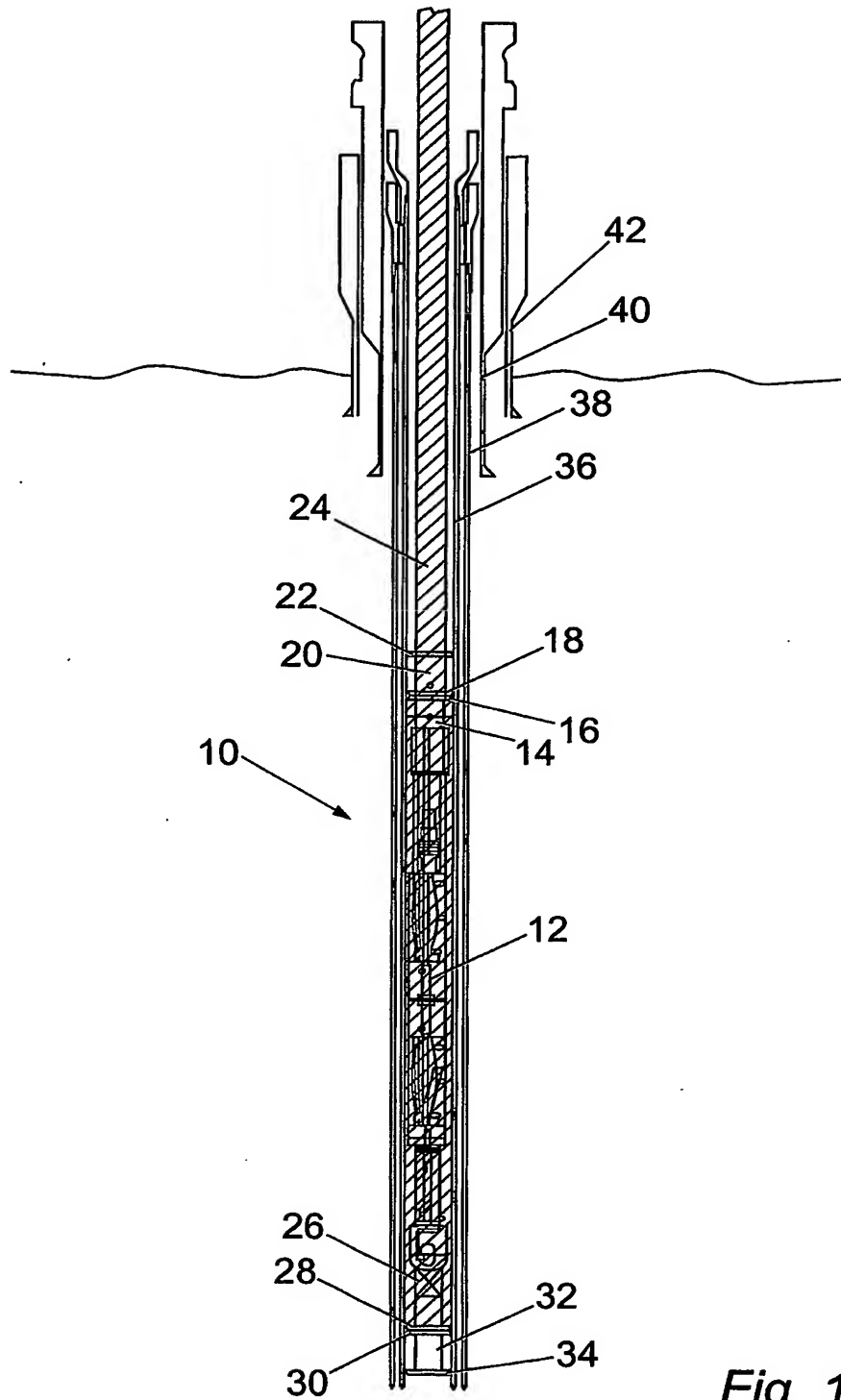


Fig. 1

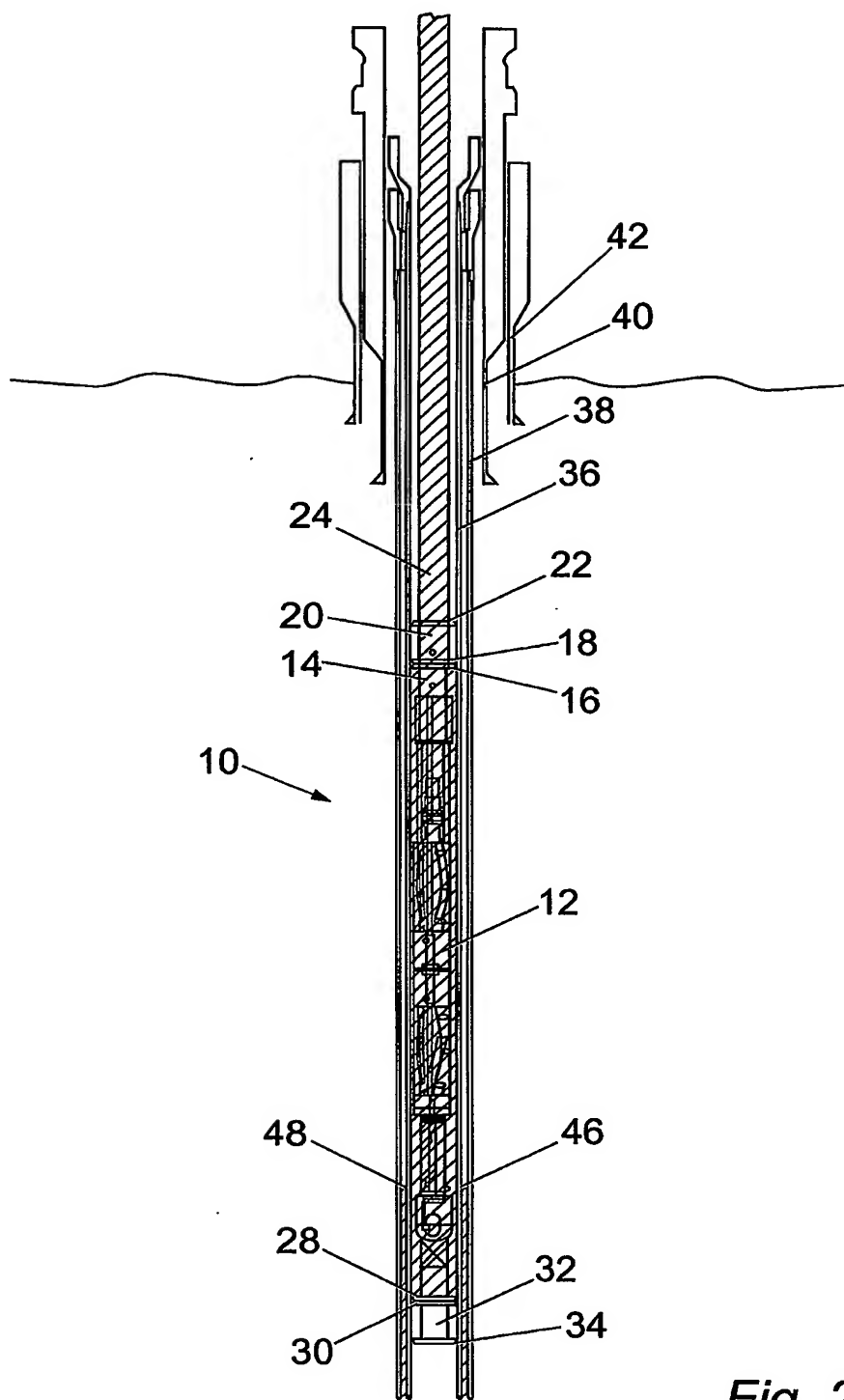


Fig. 2

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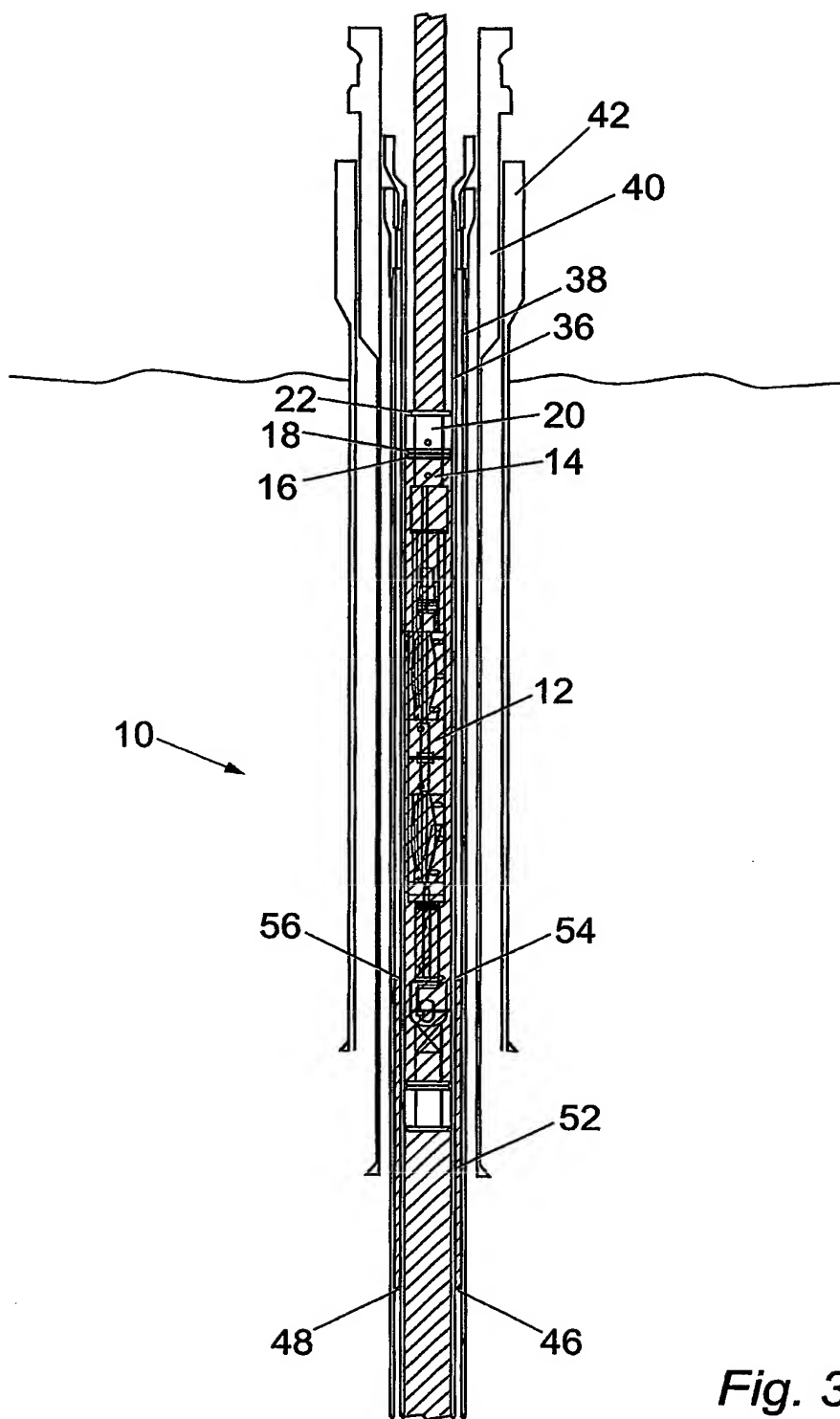


Fig. 3

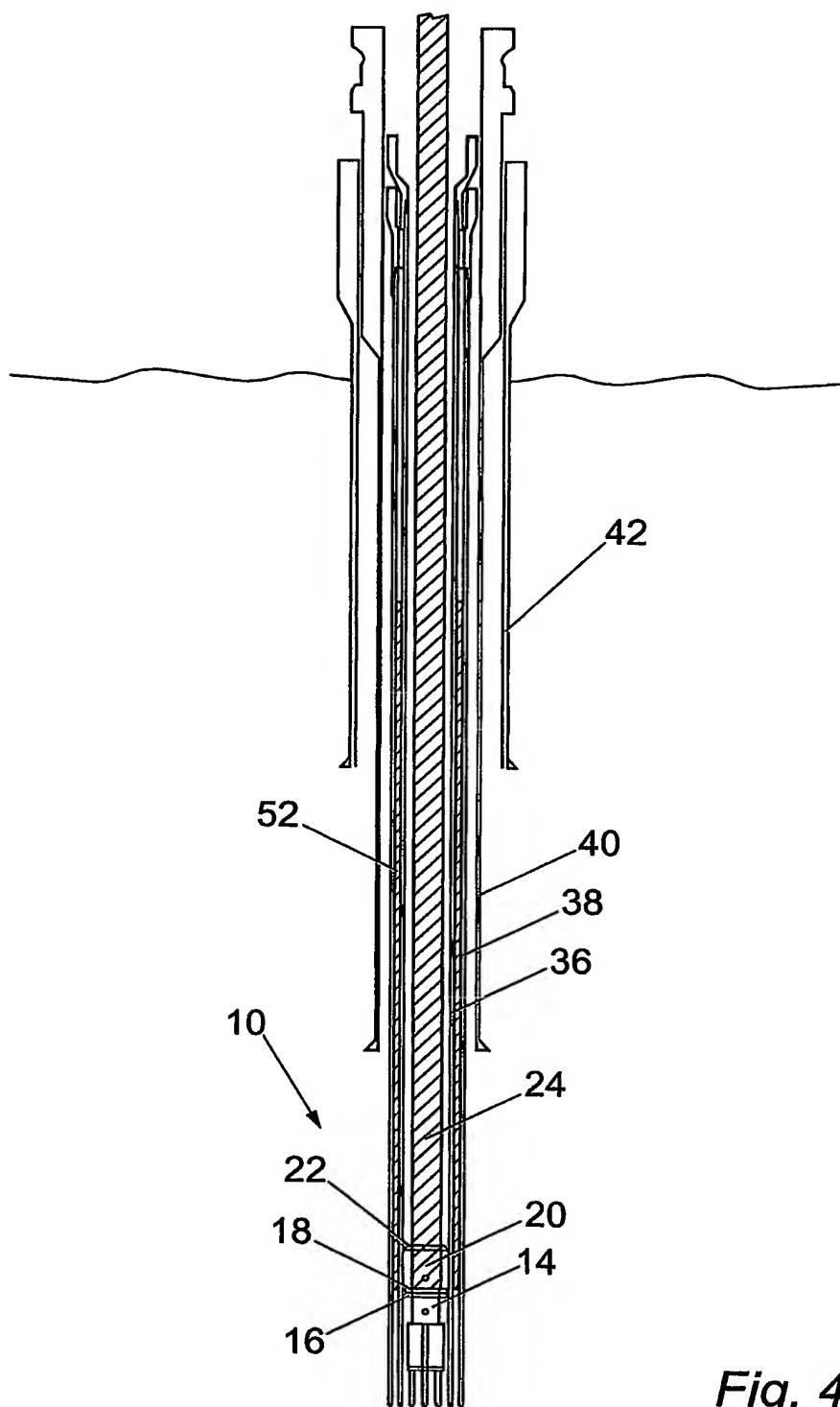


Fig. 4

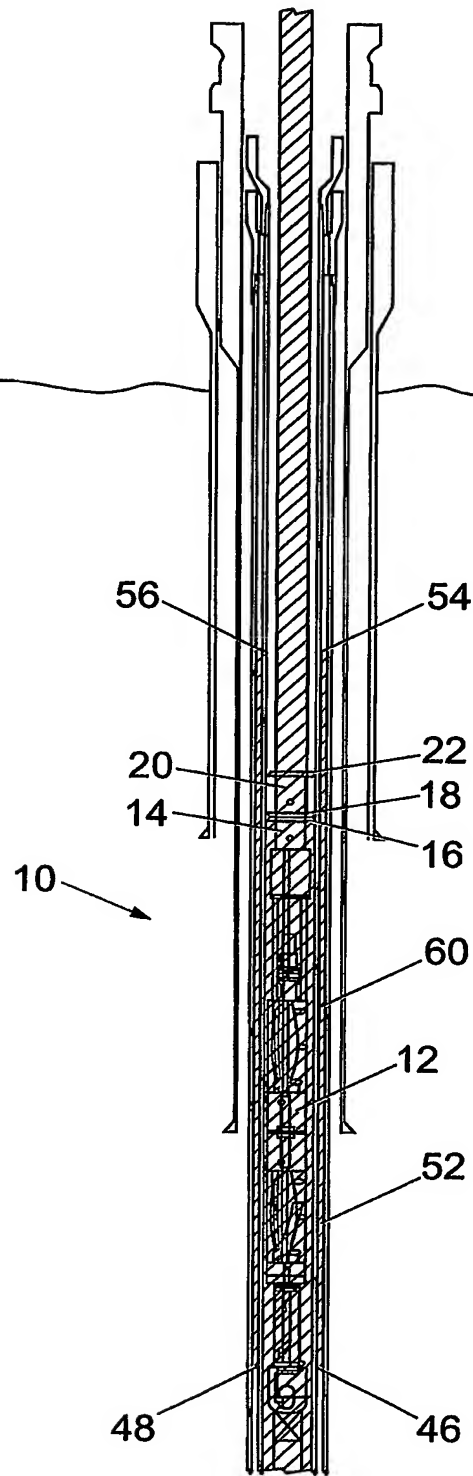


Fig. 5

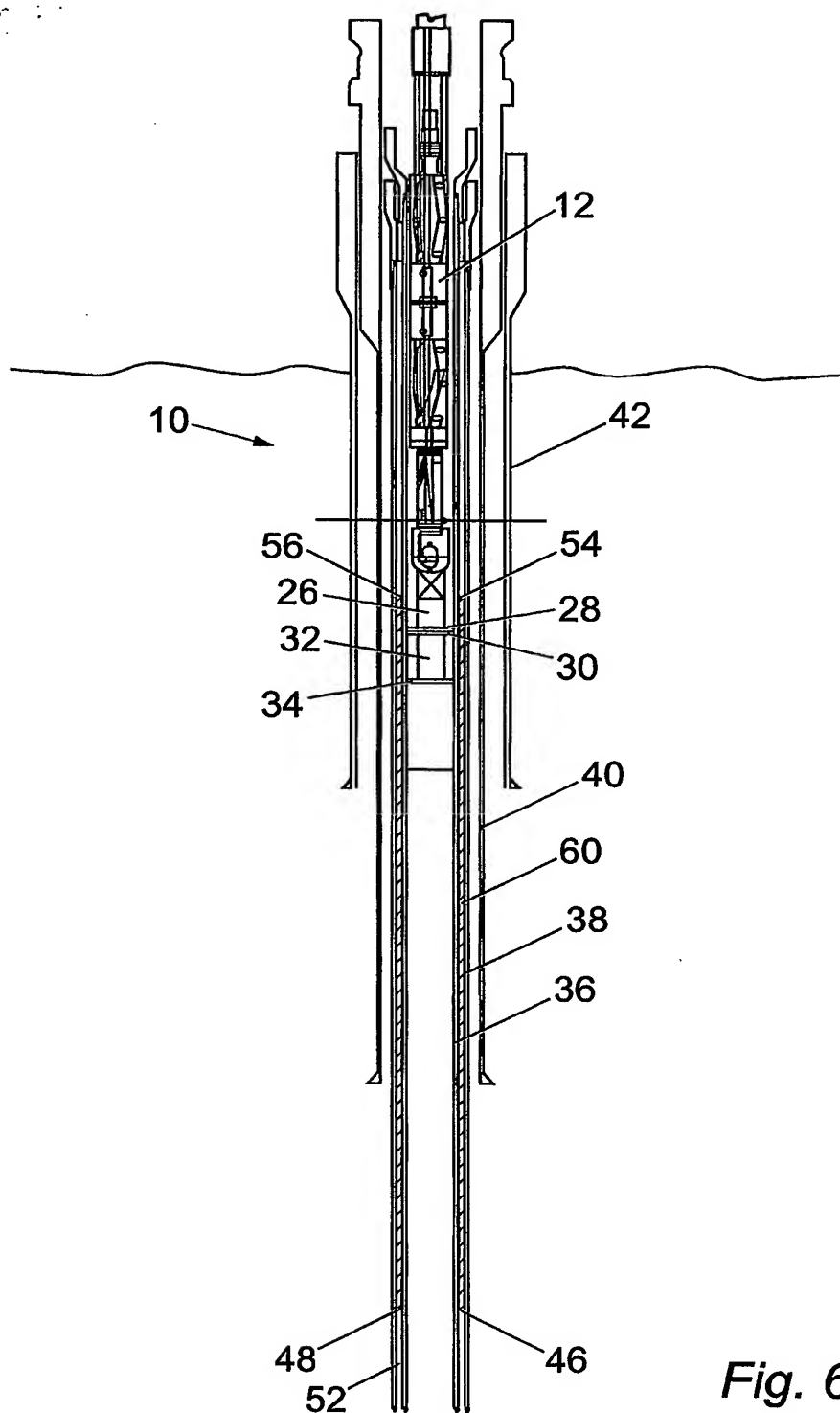


Fig. 6

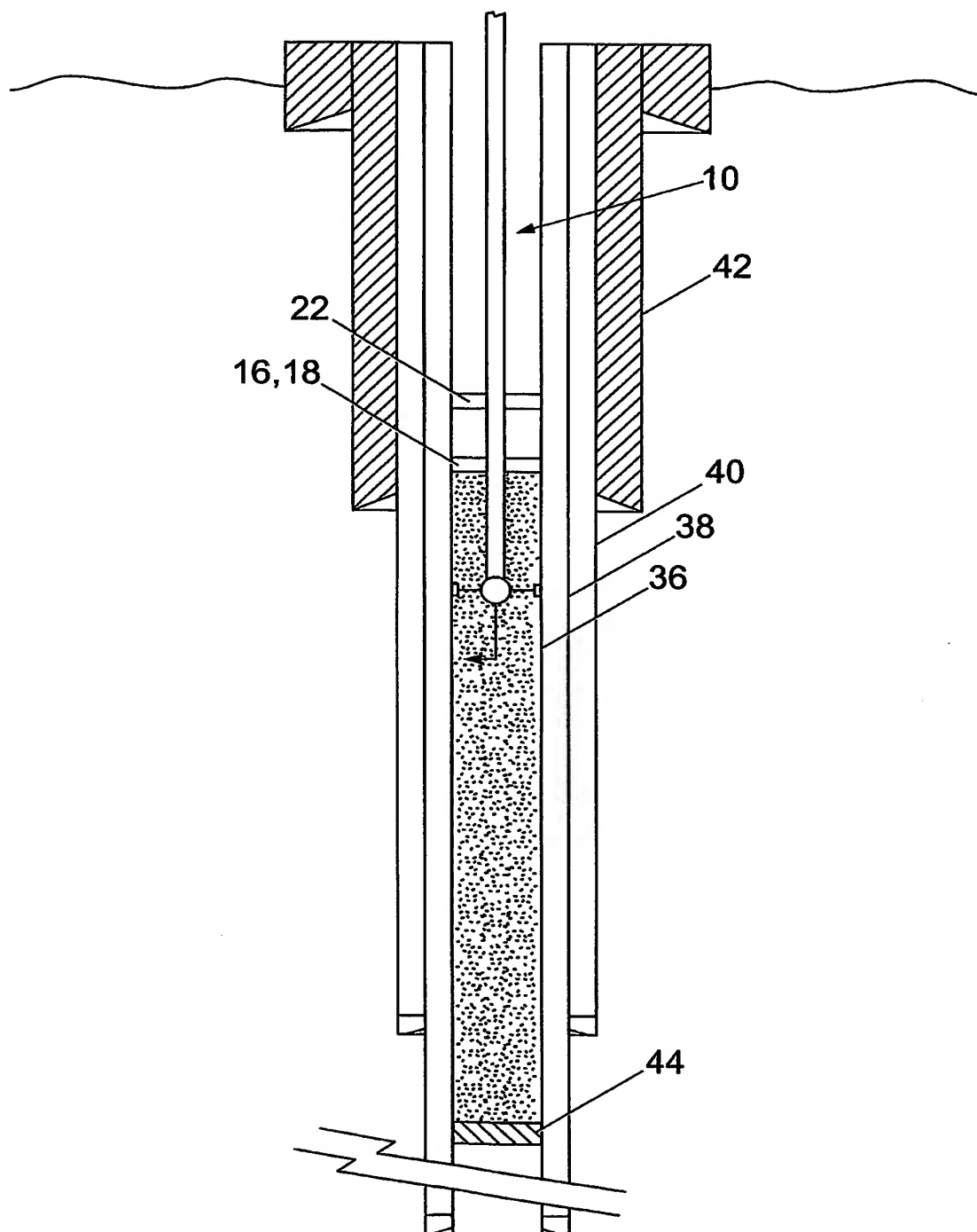


Fig. 7

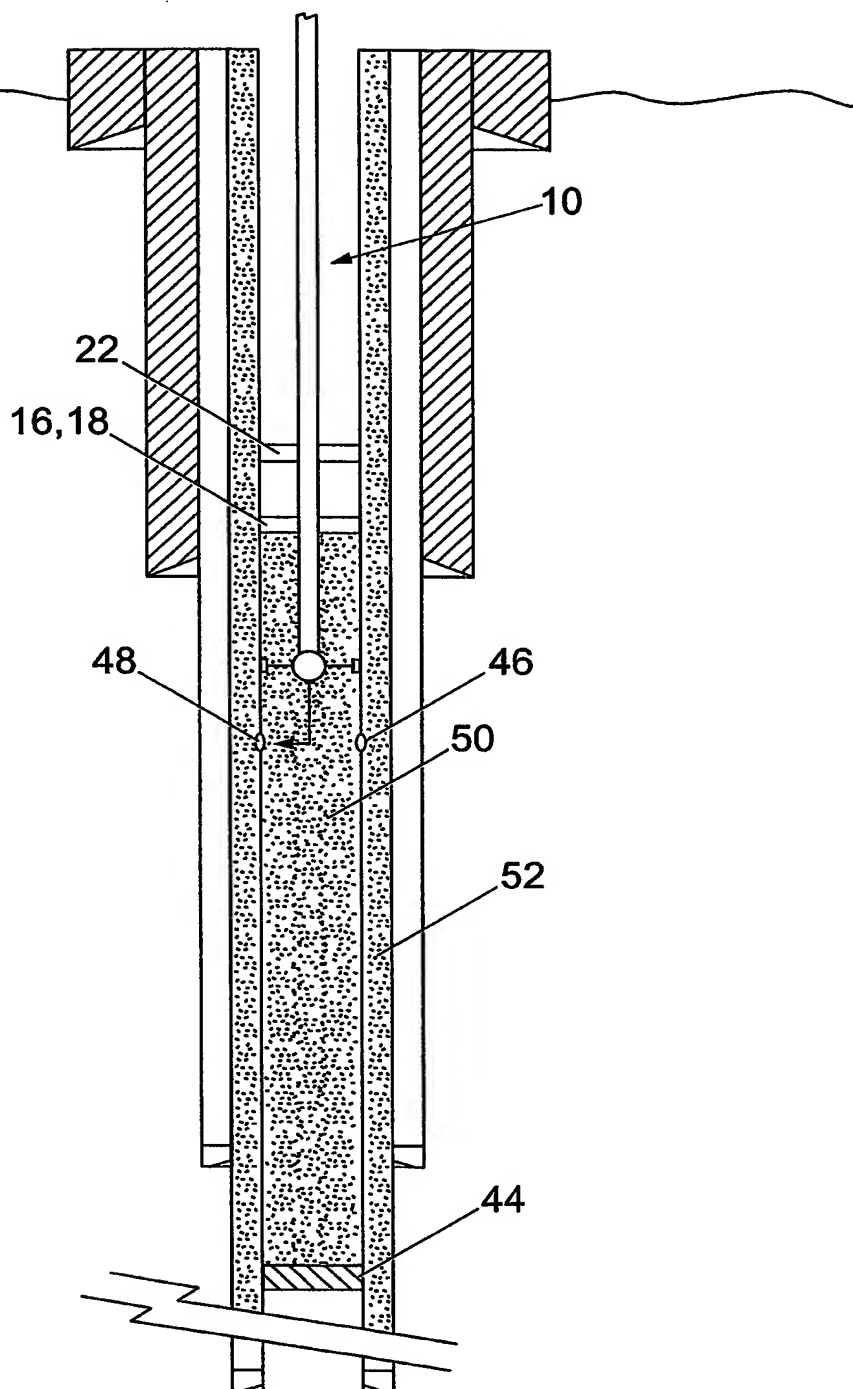


Fig. 8

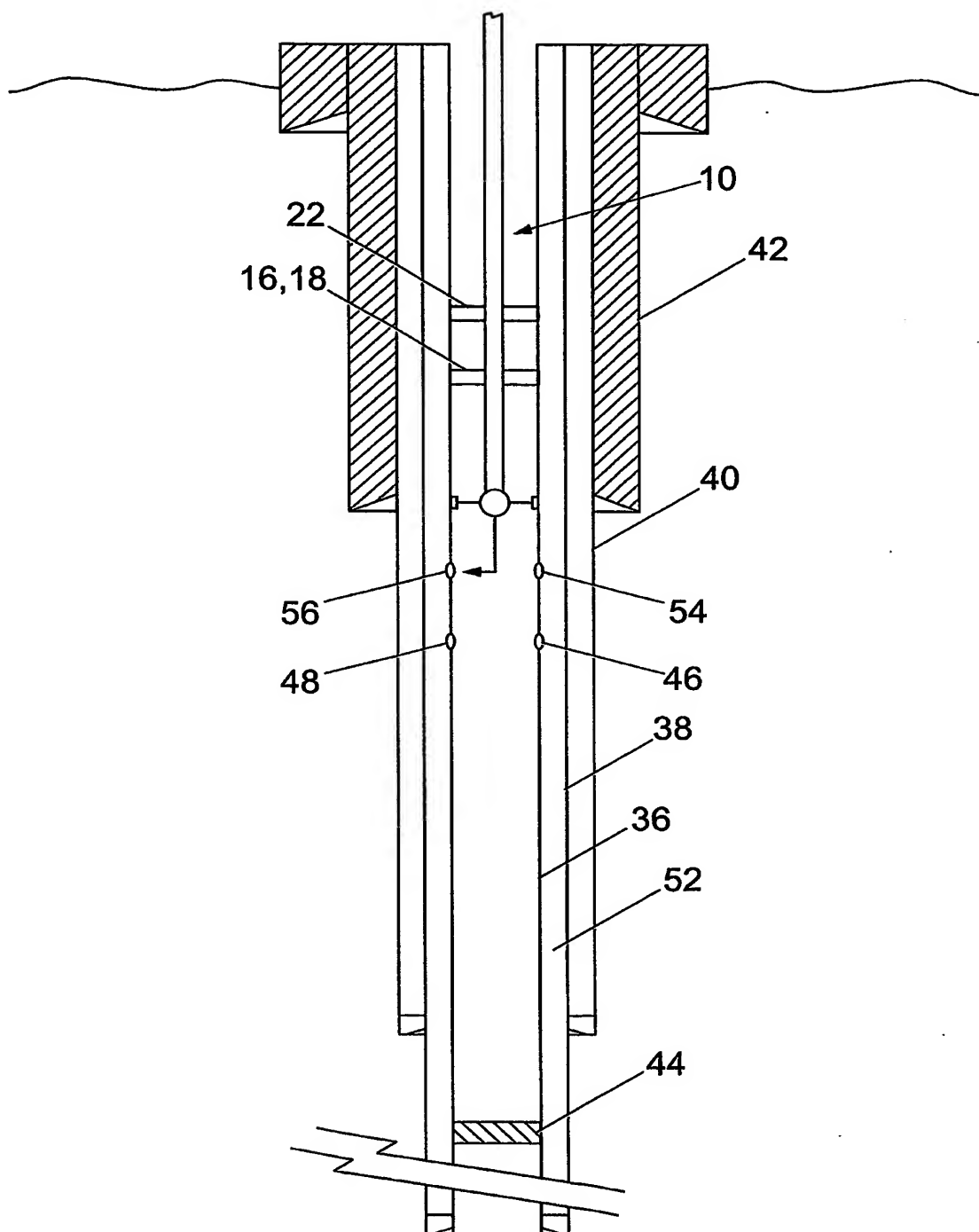


Fig. 9

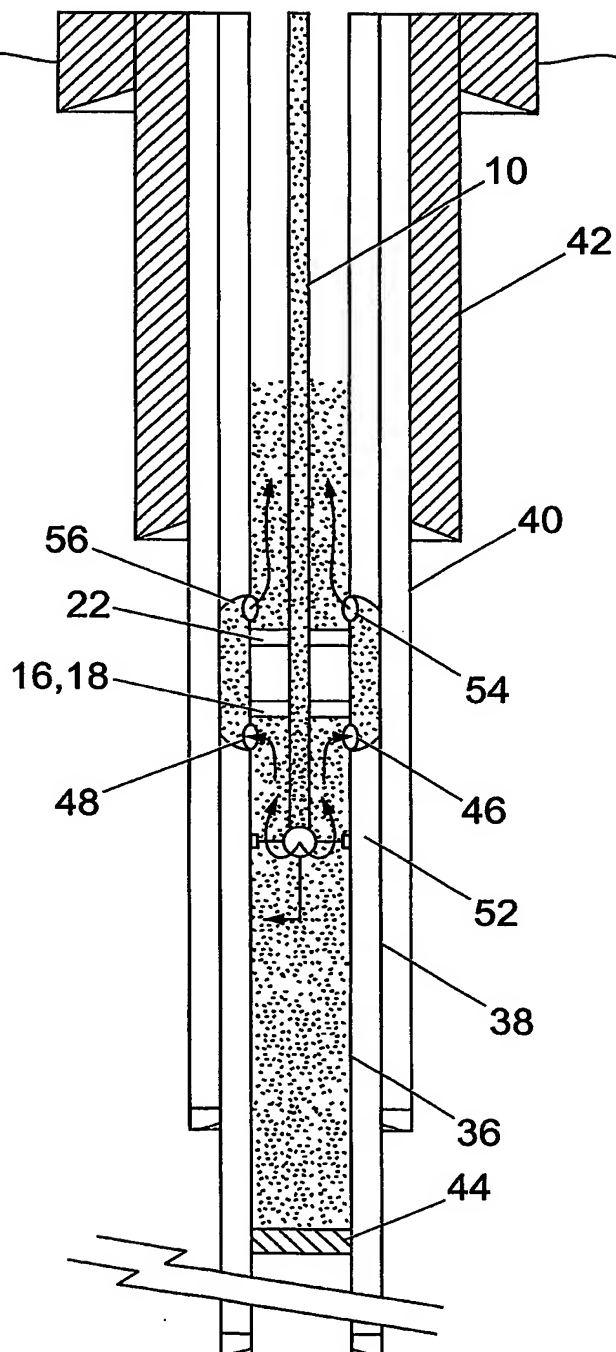


Fig. 10

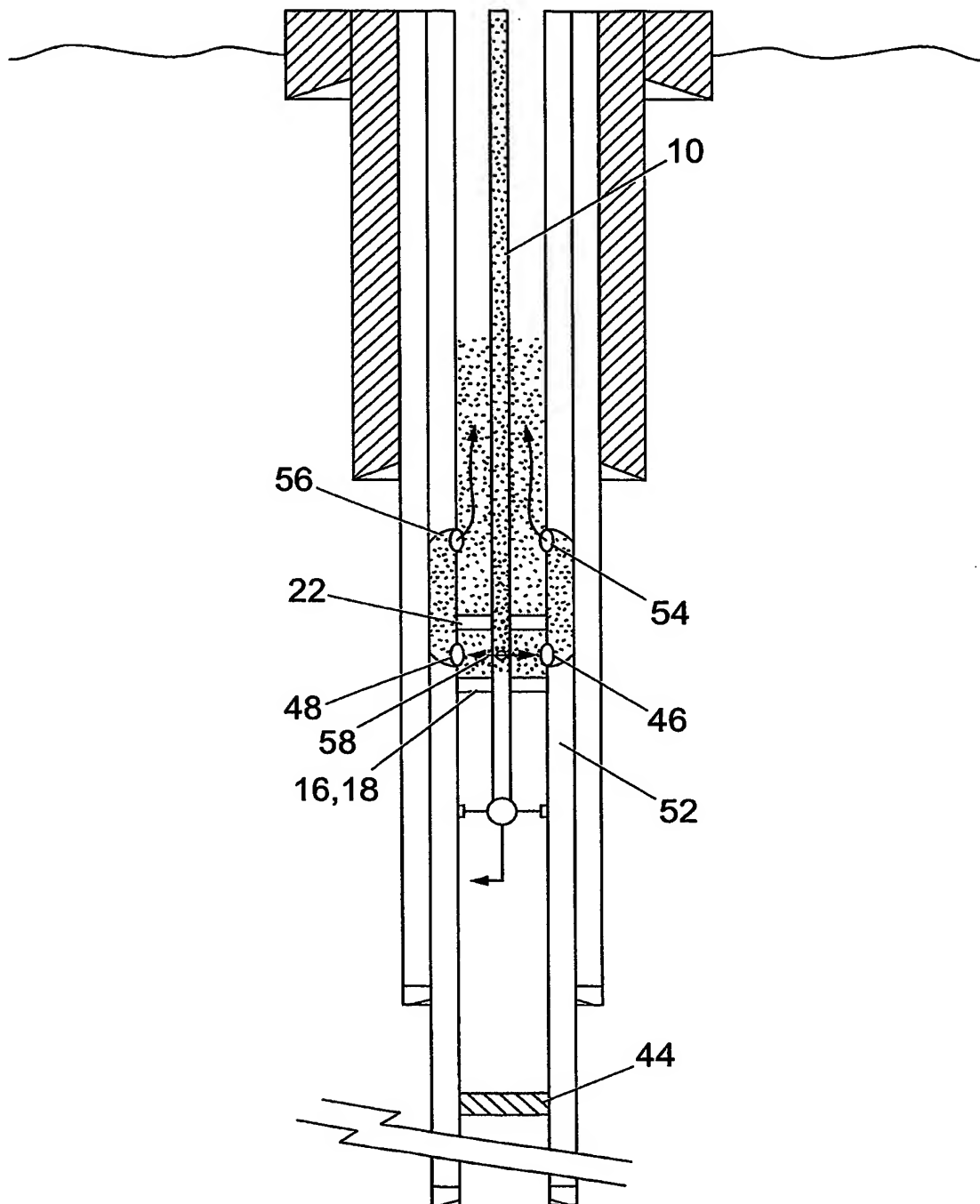


Fig. 11

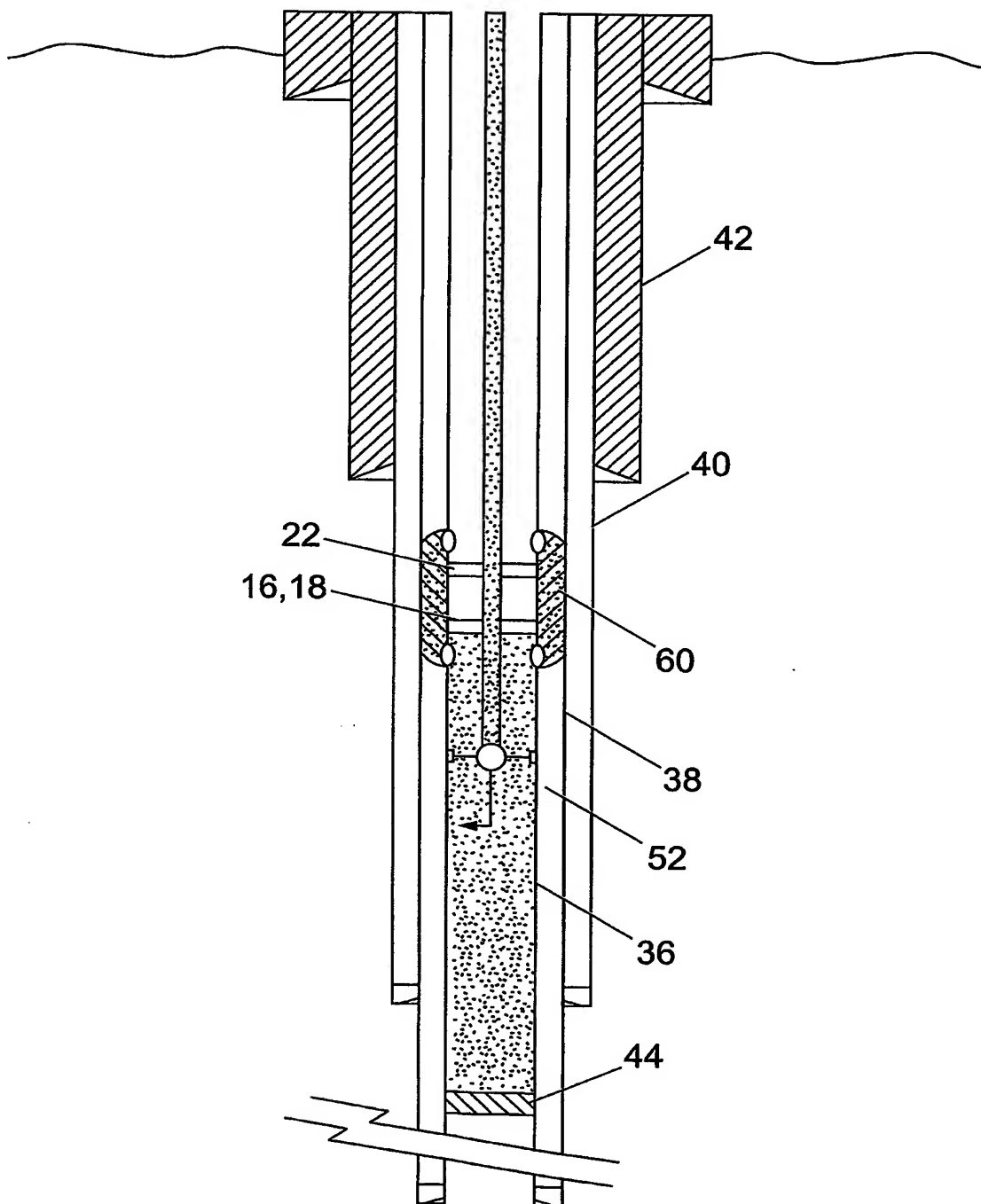


Fig. 12

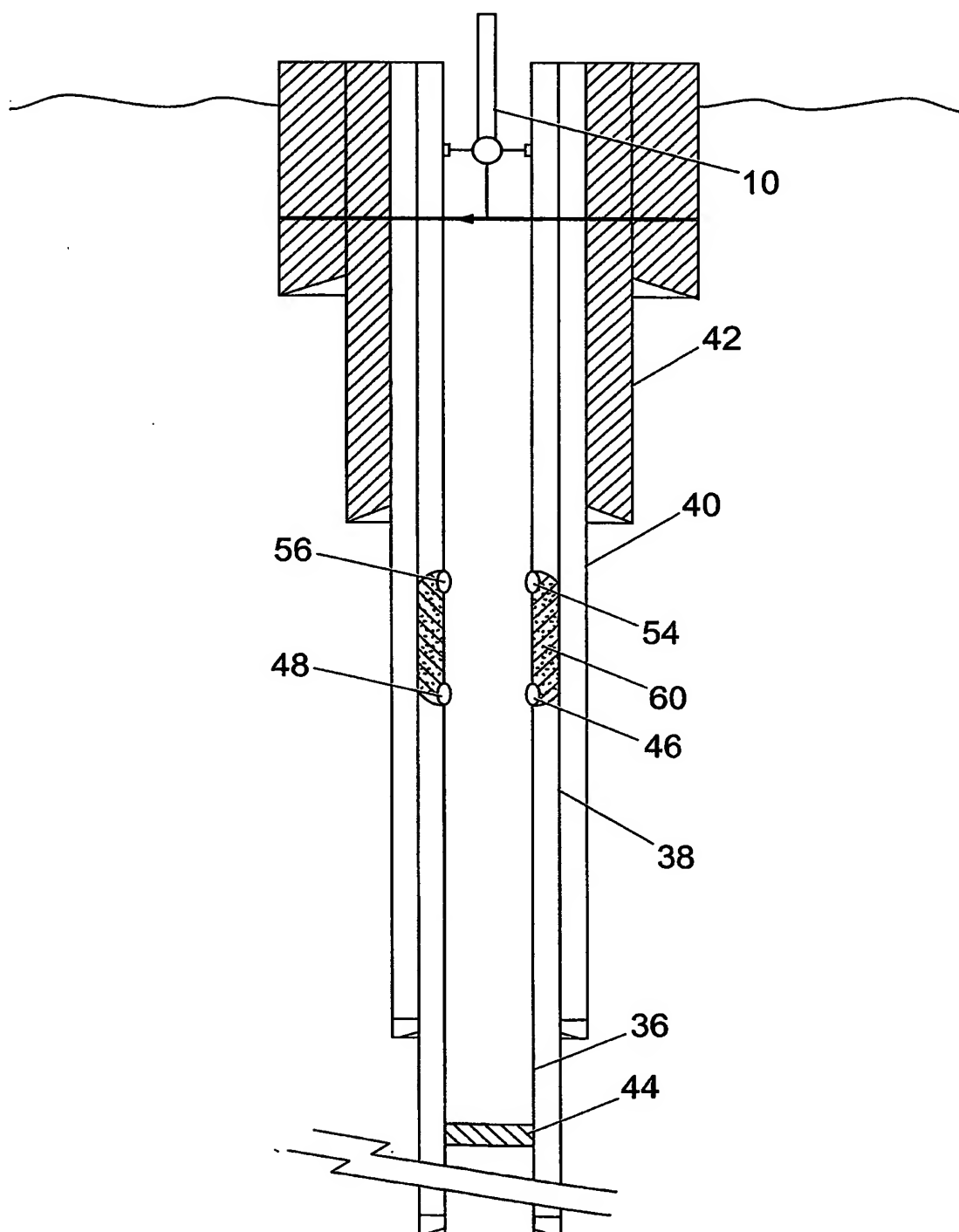
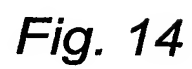


Fig. 13



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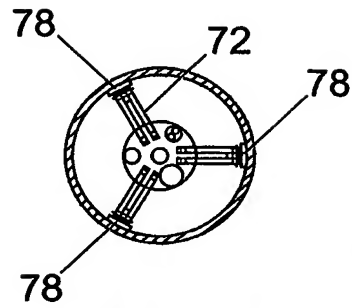


Fig. 15a

12 →

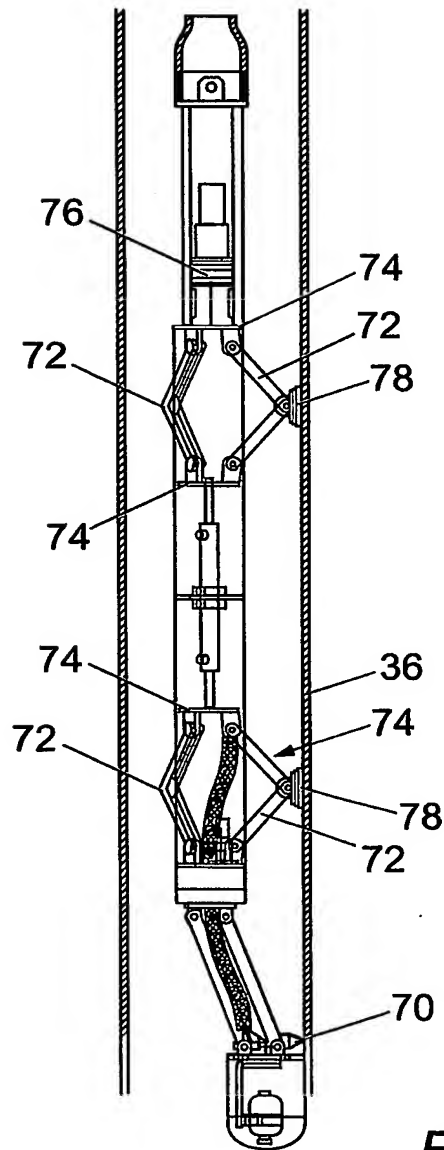


Fig. 15b

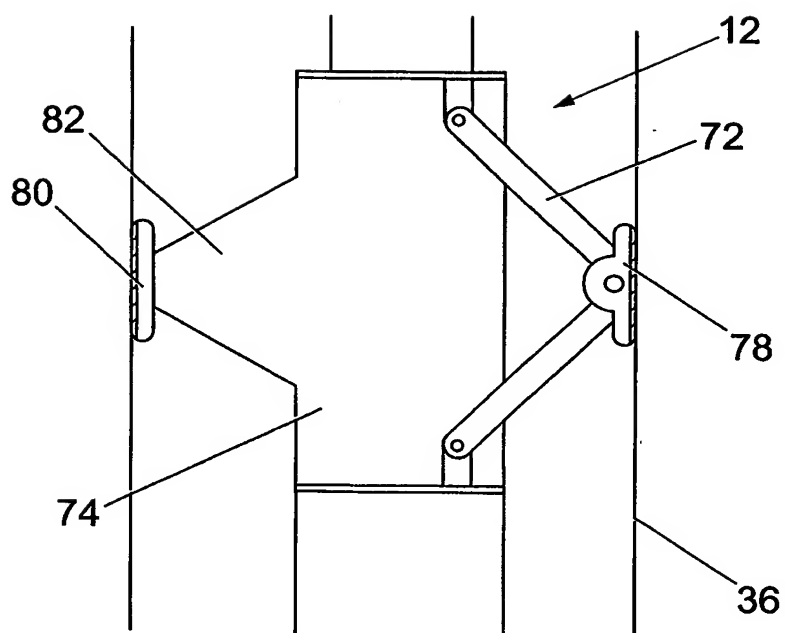


Fig. 16

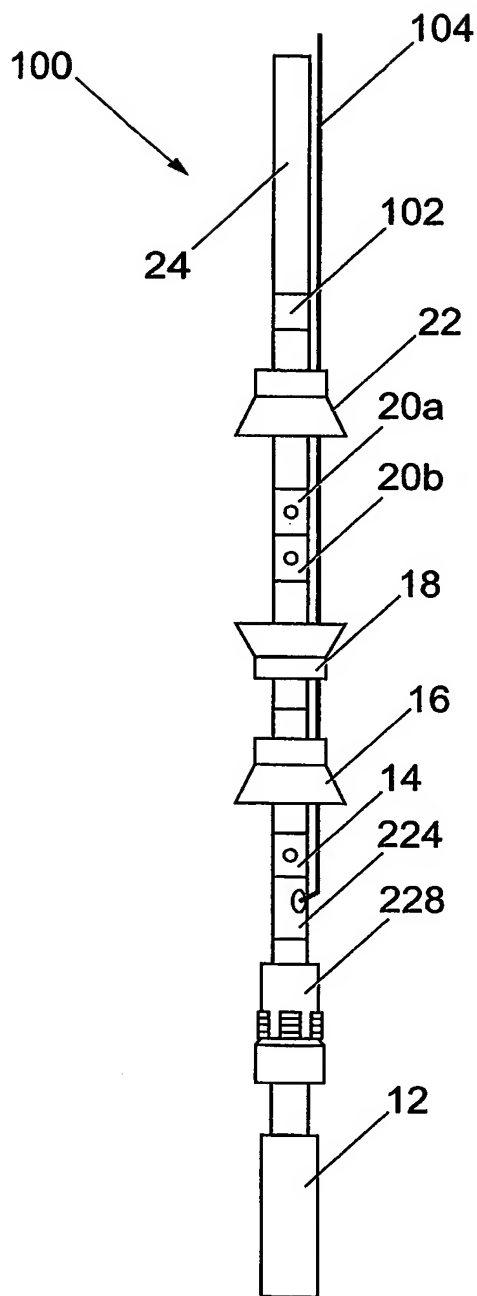


Fig. 17

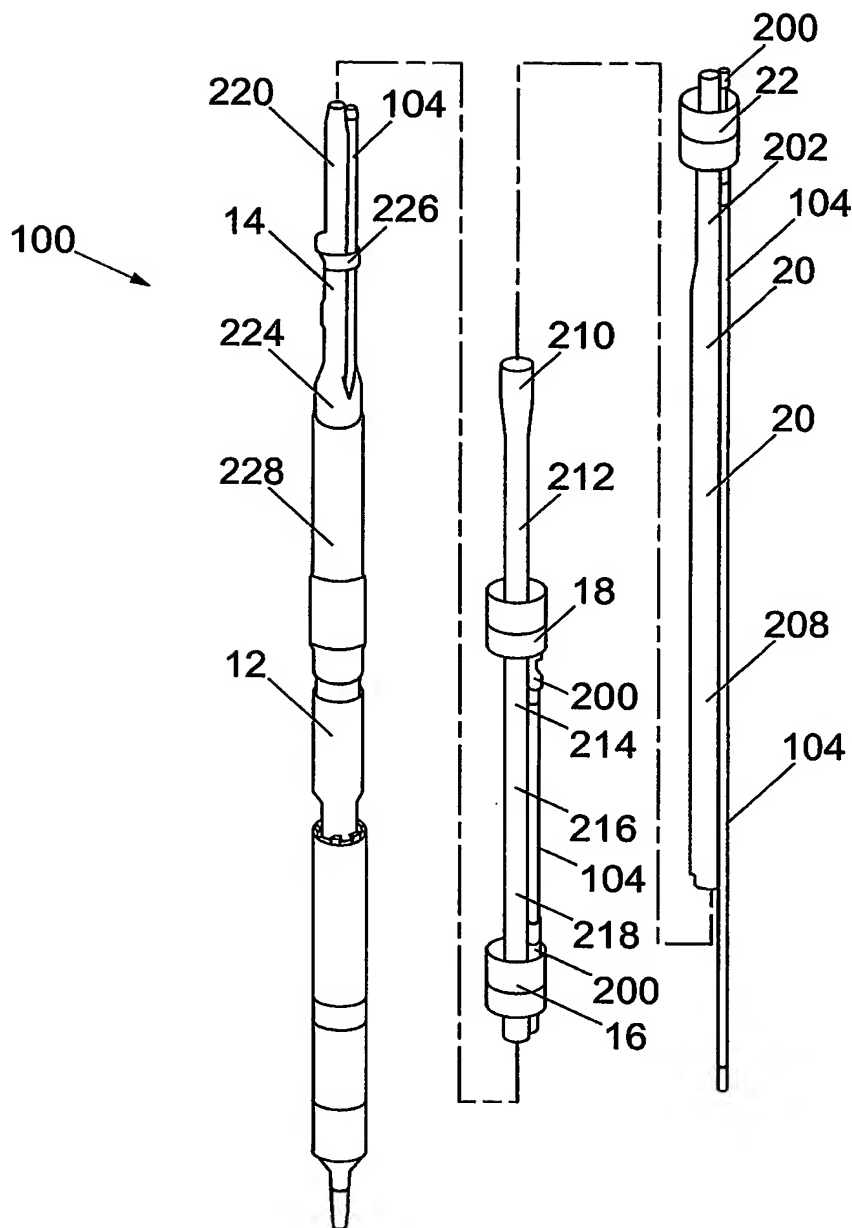


Fig. 18

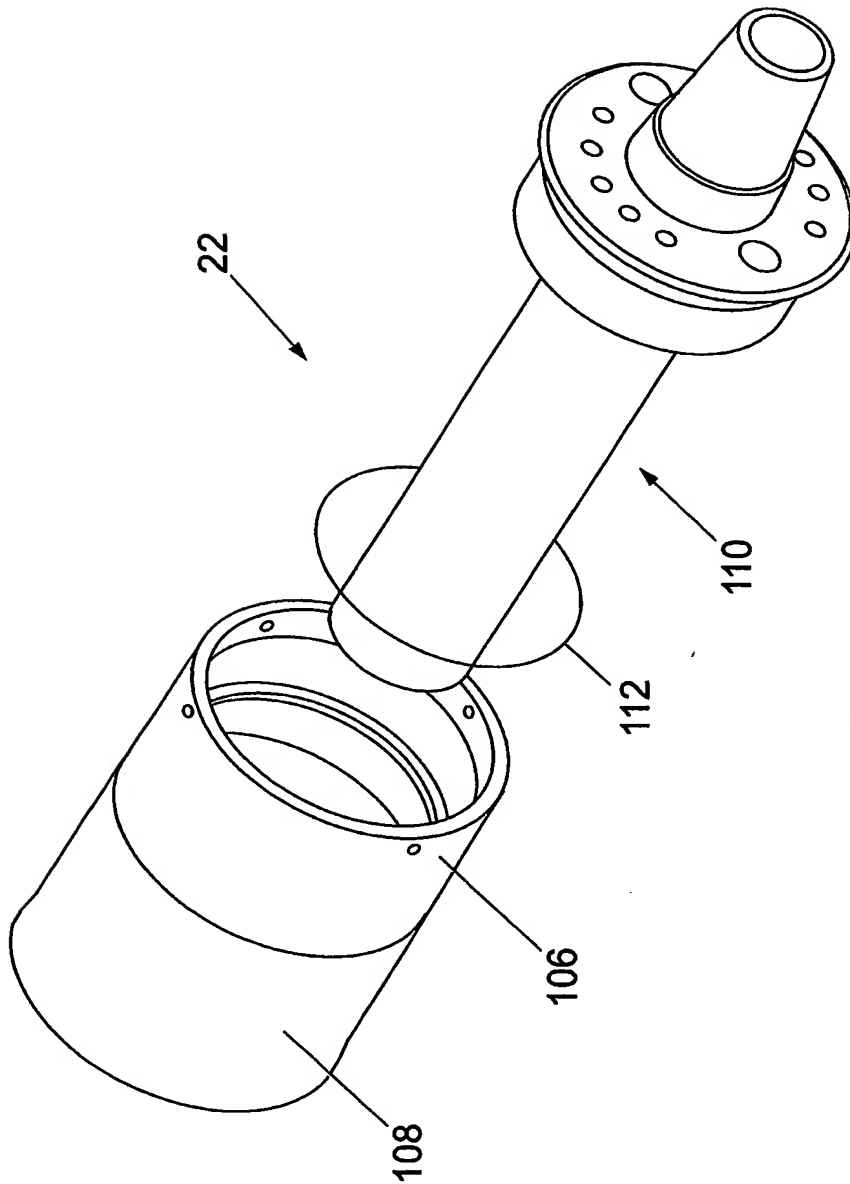


Fig. 19

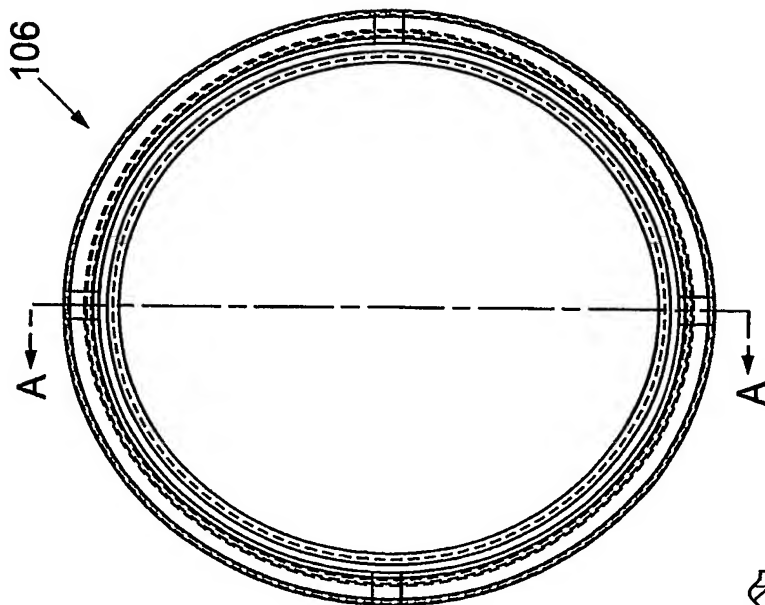


Fig. 20

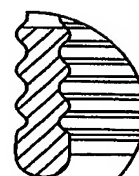


Fig. 22

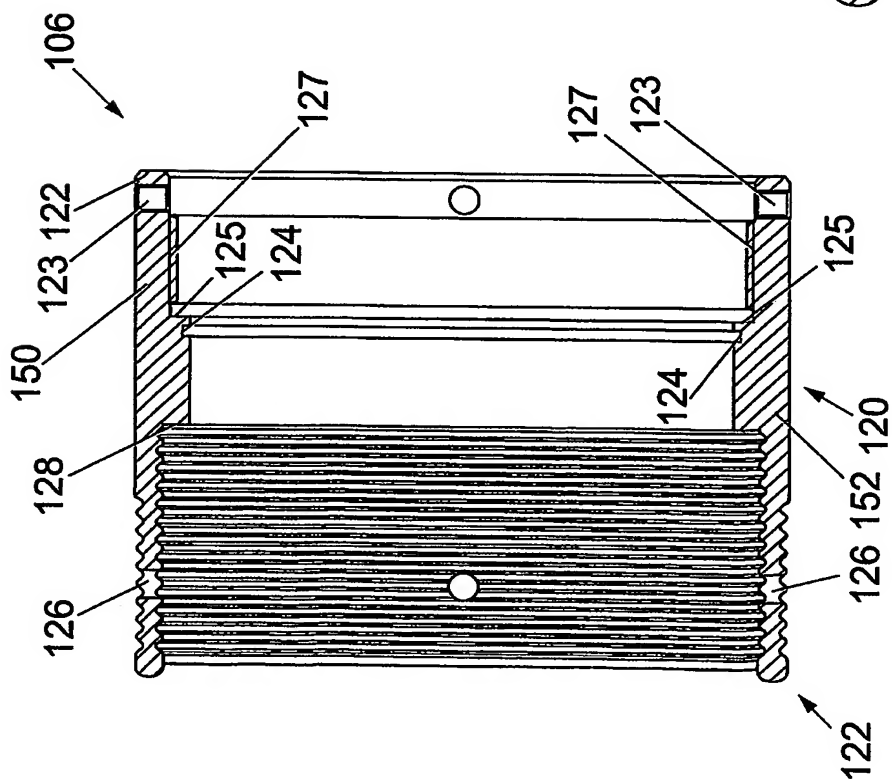


Fig. 21

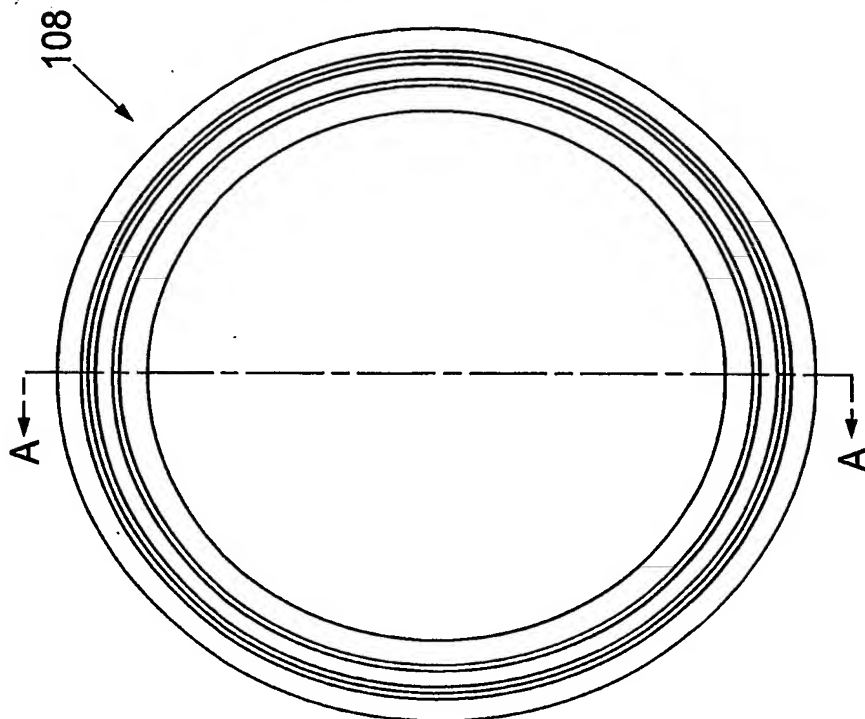


Fig. 23

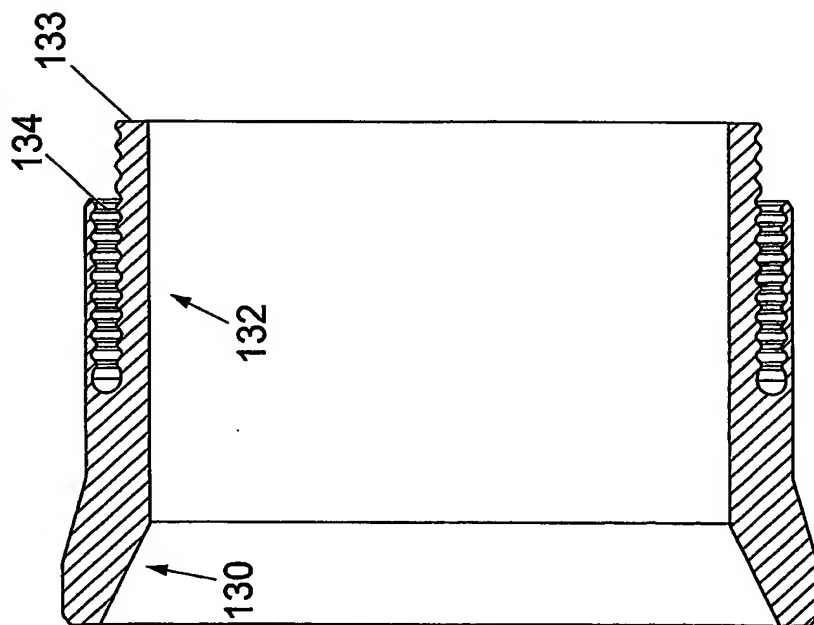


Fig. 24

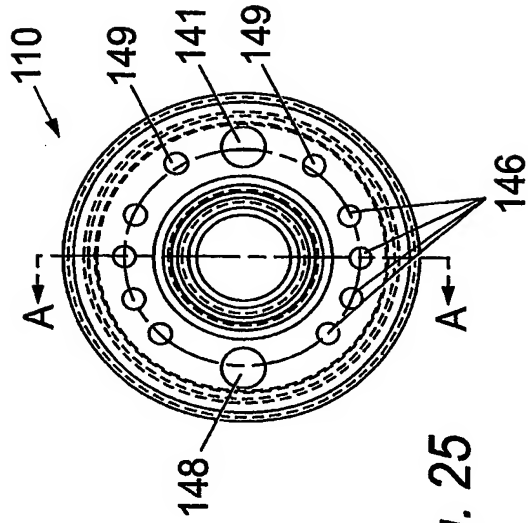


Fig. 25

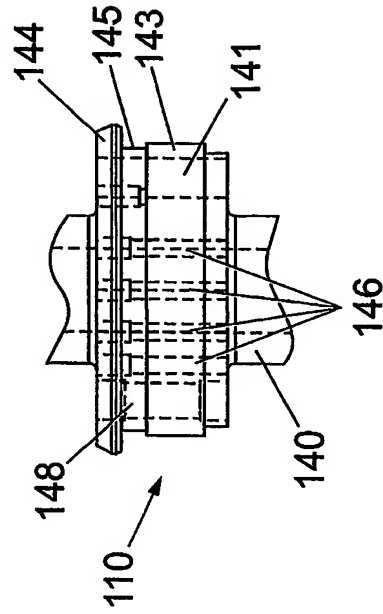


Fig. 28

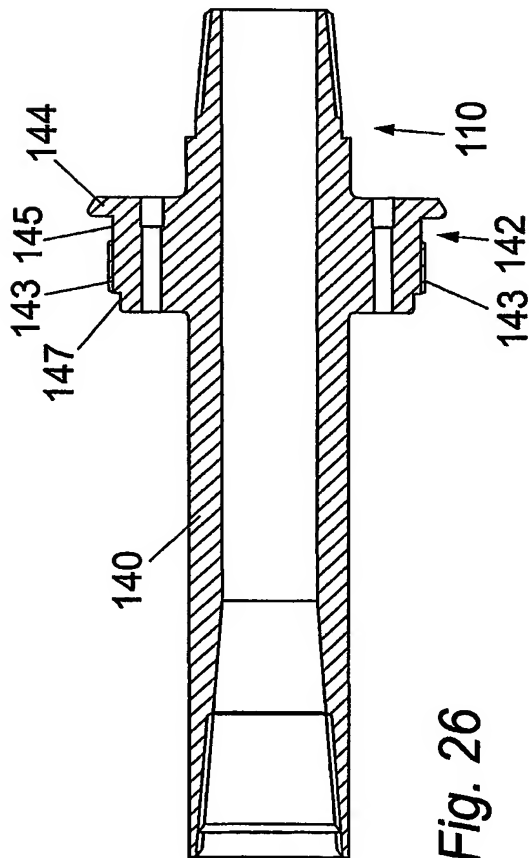


Fig. 26

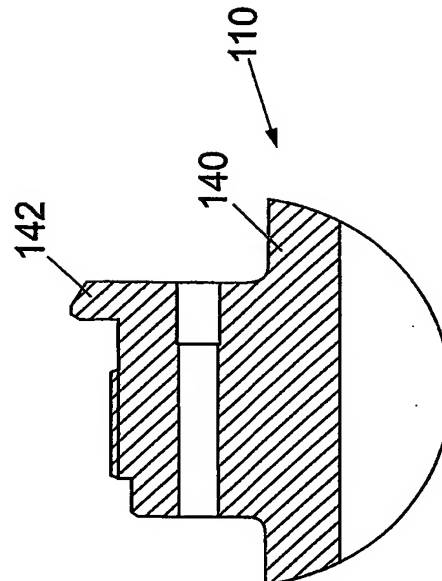


Fig. 27

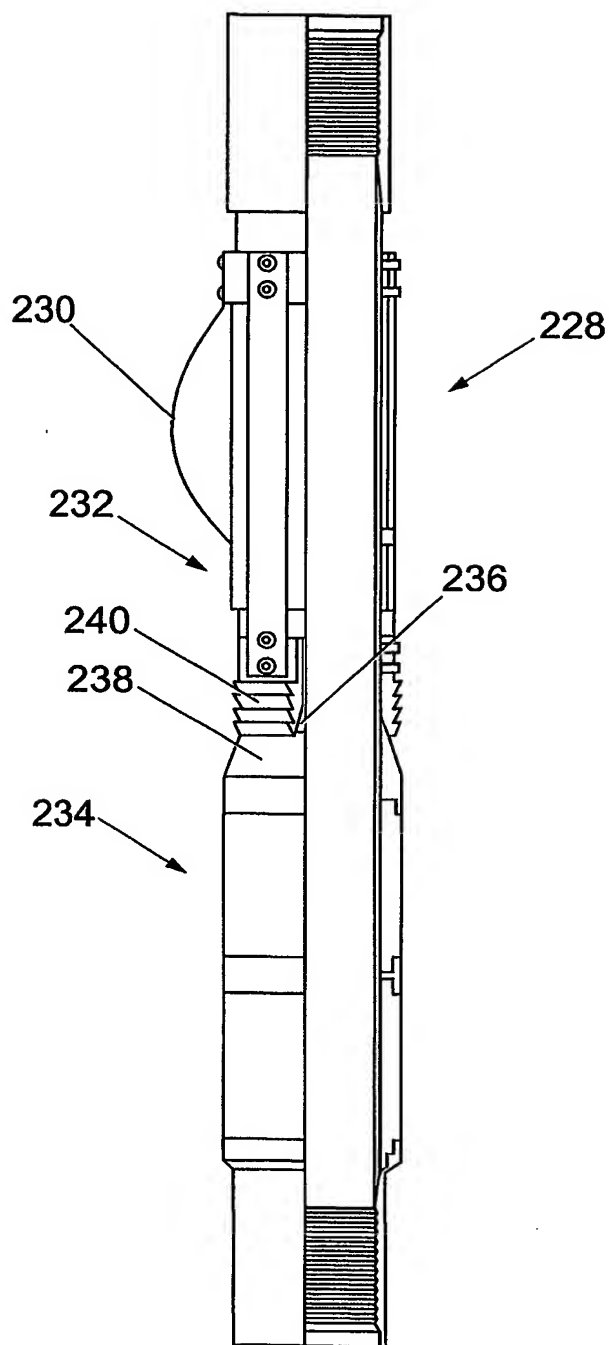


Fig. 29

INTERNATIONAL SEARCH REPORT

International Application No
PCT/GB 03/03542

A. CLASSIFICATION OF SUBJECT MATTER

IPC 7 E21B23/00 E21B29/06 E21B43/114 E21B33/124

According to International Patent Classification (IPC) or to both national classification and IPC

B. FIELDS SEARCHED

Minimum documentation searched (classification system followed by classification symbols)

IPC 7 E21B

Documentation searched other than minimum documentation to the extent that such documents are included in the fields searched

Electronic data base consulted during the international search (name of data base and, where practical, search terms used)

EP0-Internal

C. DOCUMENTS CONSIDERED TO BE RELEVANT

Category *	Citation of document, with indication, where appropriate, of the relevant passages	Relevant to claim No.
X	US 5 101 895 A (GILBERT HORACE E) 7 April 1992 (1992-04-07) column 3, line 8,32-34,,CLAIM,1; figures 1A,1B	1,3,4, 12-14
Y	---	2,5-11
Y	US 5 957 198 A (HAYNES MICHAEL JONATHON) 28 September 1999 (1999-09-28) figure 2	2,5-10
Y	---	
Y	US 5 381 631 A (RAGHAVAN CHIDAMBARAM ET AL) 17 January 1995 (1995-01-17) figures 3,4	11
A	---	
	US 6 012 526 A (JACKSON JAMES K ET AL) 11 January 2000 (2000-01-11) the whole document	11

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☒ Further documents are listed in the continuation of box C.

☒ Patent family members are listed in annex.

* Special categories of cited documents :

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O document referring to an oral disclosure, use, exhibition or other means

P document published prior to the international filing date but later than the priority date claimed

T later document published after the international filing date or priority date and not in conflict with the application but cited to understand the principle or theory underlying the invention

X document of particular relevance; the claimed invention cannot be considered novel or cannot be considered to involve an inventive step when the document is taken alone

Y document of particular relevance; the claimed invention cannot be considered to involve an inventive step when the document is combined with one or more other such documents, such combination being obvious to a person skilled in the art.

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Date of the actual completion of the international search

21 November 2003

Date of mailing of the international search report

28/11/2003

Name and mailing address of the ISA

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INTERNATIONAL SEARCH REPORT

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